PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates — 4220-UR-117

FINAL DECISION

This is the Final Decision concerning the application of Northern States Power Company–Wisconsin, doing business as Xcel Energy (NSPW), for authority to increase Wisconsin retail electric and natural gas rates in 2012.

Final overall rate changes are authorized consisting of a $12,155,000 annual rate increase for Wisconsin retail electric operations, a 2.14 percent increase, and a $2,924,000 annual rate increase for Wisconsin retail natural gas operations, a 2.37 percent increase, for the test year ending December 31, 2012, based on a 10.40 percent return on common equity. In addition to these increases, net proceeds from the U.S. Department of Energy (DOE) litigation settlement of $12,945,000 will be returned to retail electric customers as a one-time bill credit in 2012.

Introduction

On June 1, 2011, NSPW filed for authority to increase its Wisconsin retail electric and natural gas rates on January 1, 2012. On June 17, 2011, NSPW revised its application resulting in a request of a $29,235,000 (5.14 percent) increase for retail electric utility operations and an $8,034,000 (6.56 percent) increase for retail natural gas utility operations. Proposed rates were based on a 10.75 percent return on common equity (ROE).

In addition to its request to increase Wisconsin retail rates for its 2012 filed deficiencies, NSPW indicated that it will either need to file a rate reopener or full rate case in 2012 to adjust its retail rates for 2013.

On July 26, 2011, a prehearing conference was held to determine the issues that will be addressed in this docket and to establish a schedule for the hearing. On August 16, 2011, NSPW supplemented its filings by requesting that the Commission authorize the accrual of Excess Allowance for Funds Used during Construction (AFUDC) on all Construction Work in Progress (CWIP).

On November 2, 2011, a technical hearing for the revised rate application was held in Madison. On November 3, 2011, public hearings were held in Madison and La Crosse.

The Commission considered this matter at its open meeting on December 8, 2011.

The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Others who appeared are listed in the Commission's files.

Findings of Fact

1. Presently authorized rates for NSPW's Wisconsin retail electric utility operations will produce operating revenues of $569,018,000 for the test year ending December 31, 2012, which results in an adjusted net operating income of $53,885,000 and an annual revenue deficiency of $12,155,000. Presently authorized electric rates of NSPW are insufficient.

2. Presently authorized rates for NSPW's Wisconsin retail natural gas utility operations will produce operating revenues of $123,226,000 for the test year ending December 31, 2012, which results in an adjusted net operating income of $5,416,000 and an annual revenue deficiency of $2,924,000. Presently authorized natural gas rates of NSPW are insufficient.

3. For the Wisconsin retail electric utility operations, the estimated rate of return on average net investment rate base of $717,914,000 at current rates for the test year is 7.51 percent, which is inadequate.

4. For the Wisconsin retail natural gas utility operations, the estimated rate of return on average net investment rate base of $84,126,000 at current rates for the test year is 6.44 percent, which is inadequate.

5. A reasonable increase in operating revenue for the test year to produce an 8.52 percent return on NSPW's average net investment rate base for Wisconsin retail electric operations is $12,155,000.

6. A reasonable increase in operating revenue for the test year to produce an 8.52 percent return on NSPW's average net investment rate base for Wisconsin retail natural gas operations is $2,924,000.

7. NSPW's filed operating income statements and net investment rate bases for the test year, as adjusted for Commission decisions, are reasonable.

8. It is appropriate to return the DOE settlement proceeds and accrued interest as one-time credits on customers' bills within 90 days of the effective date of this Final Decision.

9. It is reasonable for NSPW to notify each customer with an explanation of the DOE settlement credit.

10. If NSPW underrefunds to its Wisconsin retail ratepayers any amounts from the DOE settlement funds including interest, it is reasonable that such amounts be deferred until a future NSPW proceeding with interest at 0.25 percent.

11. It is reasonable for NSPW to file with the Commission a report of actual DOE settlement amounts refunded to customers as soon as possible after the refunds are made.

12. It is reasonable for NSPW to work with Commission staff to determine, at a later date, whether a reopener or a full case is appropriate for a 2013 test year.

13. A 2012 test-year total fuel and transmission cost of $1,340,454,000 for the total NSP System is reasonable.

14. A test-year fuel rules cost of monitored fuel of $1,163,675,937, or $25.19 per megawatt hour (MWh), as shown in Appendix D, is reasonable.

15. It is reasonable that the monitored fuel costs authorized in this proceeding be considered the approved fuel cost plan for the 2012 plan year that complies with Wis. Stat. § 196.20(4)(c).

16. It is reasonable to monitor all fuel costs, excluding direct Cross-State Air Pollution Rule (CSAPR) compliance costs, using an annual bandwidth of plus or minus 2 percent.

17. It is reasonable to defer costs incurred during 2012 that are direct CSAPR compliance costs, with a zero percent tolerance band and carrying costs set at the utility's authorized cost of short-term debt.

18. It is reasonable to use the 2012 New York Mercantile Exchange (NYMEX) futures Henry Hub natural gas prices from November 15, 2011, as the basis for forecasting test-year cost of electric generation from natural gas.

19. It is reasonable to use the 2012 NYMEX futures prices for the Cinergy Hub for peak and off-peak energy from November 15, 2011, as the basis for forecasting test year Midwest Independent Transmission System Operator, Inc. (MISO), marginal energy prices.

20. It is reasonable to forecast test-year locational marginal price (LMP) basis differentials between the Cinergy Hub and the NSP system based on the latest two years historical data.

21. It is reasonable to estimate 2012 wind curtailments based on those observed from October 2010 through September 2011.

22. It is reasonable to estimate wind generation from the Nobles wind farm based on a 37 percent annual capacity factor for estimating fuel costs and associated production tax credits.

23. It is reasonable to use equivalent force outage rates (EFOR) in PROSYM based on the five-year historical EFORs as calculated by NSPW.

24. It is reasonable to direct Commission staff, NSPW, and the Citizens' Utility Board (CUB), and other interested intervenors who participated in this proceeding to work together to develop a specific definition of directly-incurred CSAPR compliance costs. In the event that Commission staff, NSPW, CUB, or other interested intervenors disagree with respect to the definition of direct CSAPR compliance costs, authority is delegated to the Administrator of the Gas and Energy Division to resolve any such disagreements.

25. It is reasonable to require NSPW to keep Commission staff apprised of its CSAPR compliance strategy and any changes thereto, and the associated compliance costs, by meeting regularly with Commission staff to discuss its compliance strategy and by providing supporting documentation for all deferred direct CSAPR compliance costs reported in its monthly fuel cost reports so that Commission staff can report quarterly to the Commission on CSAPR compliance costs and strategies.

26. It is appropriate for Commission staff to work with all applicable Wisconsin electric utilities and CUB to address the issues brought forward by CUB concerning the annual fuel cost plan and monthly electric fuel report filings.

27. It is reasonable to follow the Commission's established Manufactured Gas Plant (MGP) accounting and ratemaking guidelines in this rate case proceeding, whereby MGP cleanup expenses are included in rates only after they occur and have been reviewed by Commission staff. Shareholders are responsible for paying the carrying costs on unamortized, deferred balances over time, as the deferrals are amortized. Because of the significant costs of the particular MGP site at issue in this proceeding, it is reasonable to authorize Commission staff and NSPW to develop alternative ratemaking methods to address MGP site cleanup costs.

28. It is reasonable to incorporate 1.5 percent payroll merit increases in 2011 and 2012 for non-union employees and 2.5 percent payroll merit increases in 2011 and 2012 for union employees under contract in the development of test-year payroll expense and related taxes.

29. It is not reasonable to include the payroll and related costs associated with the annual incentive plan costs in revenue requirements.

30. It is reasonable to use Commission staff's methodology to forecast uncollectible expense of applying a ratio of net uncollectible write-offs to revenues at present rates.

31. It is not reasonable to adjust the nuclear operating and maintenance expenses in the test year as requested by the Wisconsin Industrial Energy Group (WIEG).

32. It is reasonable to reduce depreciation expense to reflect the full 20-year life extensions recently approved by the Nuclear Regulatory Commission for the Prairie Island nuclear units and not appropriate to amortize the nuclear depreciation reserve surplus over five years.

33. It is reasonable to record the Kansas property tax in account 408.1, Taxes Other than Income Taxes.

34. It is reasonable for NSPW to accrue excess AFUDC on all CWIP.

35. It is reasonable to include all uncontested Commission staff adjustments to NSPW's filed revenue requirements.

36. In future rate filings, it is reasonable to require NSPW to provide a forecasted Ratio of Net Investment Rate Base Plus CWIP to Capital Applicable to Utility Operations Plus Accumulated Deferred Investment Tax Credit, which would include all of the components of the balance sheet presented in ratio format, by month, in order for the company to receive a return on its forecasted net working capital.

37. It is appropriate for NSPW to continue to work with Commission staff and Focus on Energy Program Administrator to ensure that Education and Training offerings are well-coordinated.

38. It is appropriate for NSPW to work with Commission staff to develop measures of success for its customer service conservation program. The measures of success should be structured to redefine, and thereby better align, NSPW's customer service conservation activities with the statewide programs. NSPW must receive Commission staff acceptance of the changes before they are implemented.

39. The reasonable level of expensed conservation costs recoverable in rates for the 2012 test year is $10,389,080 for electric operations and $3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of $9,263,041 plus an escrow adjustment of $1,126,039 to reflect the estimated overspent balance as of January 1, 2012, of

$2,252,078, amortized over two years. The level for natural gas operations consists of the conservation budget of $2,747,358 plus an escrow adjustment of $267,574 to reflect the estimated overspent balance as of January 1, 2012, of $535,147 amortized over two years.

40. A long-term range of 50 percent to 55 percent for NSPW's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

41. An appropriate target level for the test-year average common equity measured on a financial basis is 52.50 percent.

42. It is reasonable to explore further the target level for common equity in NSPW's next rate case.

43. Reasonable estimates of the debt-equivalent of NSPW's off-balance sheet obligations associated with operating leases and subsidiary debt are $7,638,707 and $1,945,000, respectively.

44. A reasonable financial capital structure for the test year consists of 52.50 percent equity, 41.10 percent long-term debt, 5.41 percent short-term debt, 0.20 percent subsidiary debt, and 0.78 percent debt equivalence for off-balance sheet obligations.

45. It is reasonable to require NSPW to submit a ten-year financial forecast in its next rate proceeding.

46. It is reasonable to require NSPW to submit in its next rate proceeding, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

47. A reasonable regulatory capital structure for the test year consists of 52.59 percent equity, 41.89 percent long-term debt, and 5.52 percent short-term debt.

48. It is reasonable to implement dividend restrictions for NSPW based on the capital structure determinations in this proceeding.

49. A reasonable interest rate for short-term borrowing through commercial paper is 0.40 percent.

50. A reasonable estimate of the cost of the new long-term debt issue for the test year is 4.69 percent.

51. A reasonable average embedded cost for long-term debt is 6.15 percent for the test year.

52. A reasonable return on equity is 10.40 percent.

53. A reasonable weighted average composite cost of capital is 8.07 percent.

54. The electric revenue allocation and rate changes shown in Appendix B are reasonable.

55. It is reasonable to modify NSPW's electric rule and regulation tariff provisions, as proposed by NSPW, which affect schedules Ex-19, Ex-19.1, Ex-34, Ex-35, Ex-38 and Ex-49.

56. It is reasonable to make the changes to NSPW's lighting tariff language, affecting schedules S-1, Ms-2.1, Ms-3.1, Ms-4.1, Ms-4.2, and Ms-6, that NSPW originally proposed with the modifications proposed by Commission staff.

57. It is reasonable to base the buyback rates for NSPW's parallel generation tariffs on locational marginal prices in the MISO market.

58. It is reasonable that the NSPW's parallel generation tariffs recognize the value of capacity in buyback rates by indicating that, should MISO implement a capacity market, NSPW shall implement a capacity credit reflecting the MISO capacity market pricing method.

59. It is reasonable that customers under NSPW's parallel generation tariffs with renewable generation facilities that generate renewable credits may negotiate a renewable credit rate for any renewable energy sold to NSPW.

60. It is reasonable to increase the capacity limit of NSPW's Pg-1 net energy billing tariff from 20 kilowatt (kW) to 100 kW.

61. It is reasonable to credit net energy billing customers at an avoided-cost rate for net surplus customer-generated energy.

62. It is reasonable to allow net energy billing customers to net their generation and consumption over the period of a year or twelve months.

63. It is not reasonable to require NSPW's net energy billing customers to size their generation facilities to match their annual load requirements.

64. It is reasonable to allow existing net energy billing customers who have generation with name plate capacity of 20 kW or less to continue to be served subject to the terms of the existing Pg-1 tariff until the Commission issues its order in the NSPW's next general rate case.

65. It is reasonable to cancel the company's Pg-1.1 net energy billing tariff for non-renewable generation facilities.

66. It is reasonable to approve NSPW's proposed modifications to its Advanced Renewable Tariff.

67. It is reasonable to approve NSPW's proposed changes to its Pg-2.1 buyback rates.

68. It is reasonable for NSPW to cancel its Customer Buyback Program Service tariff.

69. It is reasonable to direct NSPW to develop a plan to transition its Cg-5 customers to a mandatory Time of Use (TOU) rate structure.

70. It reasonable to maintain the Windsource premium at the current rate of $1.37 per 100 kWh block and to require a full analysis be done in NSPW's next rate case on the issue of the company's Windsource voluntary green pricing program.

71. It is reasonable to continue to rely on the results of one or more natural gas cost-of-service study (COSS) along with other factors, such as bill impacts, as guides for revenue allocation and rate design.

72. It is reasonable to authorize rates for natural gas service as shown in Appendix C.

73. It is reasonable to authorize a monthly distribution margin rate for residential gas service at the current charge of $10.25.

74. It is reasonable to merge the Large General Service rate class and the Interruptible Group 1 rate class into one rate class.

75. It is reasonable to close the largest volume service rate class, Cg-6, to new customers and to remove this class when the existing customer no longer subscribes to this service.

Conclusions of Law

The Commission concludes it has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter a Final Decision authorizing NSPW to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, and the fuel cost treatment set forth in Appendix D, subject to the conditions specified in this Final Decision. The rates and rules for electric and natural gas utility service in Appendices B and C are reasonable and appropriate as a matter of law.

Opinion

Applicant and its Business

NSPW is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric and natural gas utility in Wisconsin. NSPW is engaged in providing electric service to approximately 250,000 retail customers in northwestern Wisconsin and the western tip of the Upper Peninsula of Michigan. In addition, NSPW provides natural gas service to approximately 106,000 customers in Wisconsin and Michigan. NSPW is a wholly-owned subsidiary of Xcel Energy Inc. (Xcel Energy).

General

DOE Settlement Proceeds

NSPW recently applied for approval with the Commission in docket 4220-GF-116 of a credit mechanism for the settlement that was reached with the DOE relating to the partial breach of its contract to take spent nuclear fuel from Northern States Power Company-Minnesota's (NSPM) Monticello and Prairie Island nuclear generating plants. The proceeds from the settlement will be in the form of a series of payments for capital and operating and maintenance (O&M) costs recovered by the NSP companies in past and current base rates. The amount currently available for credit net of outside legal costs incurred in pursuit of the settlement is $12,945,141 on a Wisconsin retail jurisdictional basis, and is for settlements through December 31, 2008. The settlement also provides for recovery of spent nuclear fuel storage damages from January 1, 2009, through December 31, 2013. The company estimates additional damage payments for this period totaling approximately $14.3 million on a Wisconsin retail jurisdictional basis. These additional payments are estimated to begin in 2012 and go through year-end 2014. It is appropriate to address such additional payments in future NSPW proceedings.

The current settlement funds are held by NSPM in a separate interest-bearing account that earns 0.25 percent annually. NSPW indicated its strong preference to remit the settlement payments with accrued interest to customers through the use of one-time bill credits within 90 days of Commission approval because it is the most administratively efficient and timely method to return these funds to customers. NSPW proposed that the credit amounts be allocated to each customer class using the class COSS approved in NSPW's 2010 rate case based on 12 months of actual kWh usage, from July 1, 2010, through June 30, 2011.

Both CUB and WIEG agreed that the settlement funds should be returned to customers through a one-time bill credit that will provide prompt rate relief to customers. However, CUB preferred the settlement amount be allocated to the customer classes based on the 2012 test-year demand allocator as proposed by Commission staff while WIEG agreed with NSPW's proposal to allocate it using the 2010 test-year demand allocator.

Given the current economic conditions, returning the DOE settlement payments with accrued interest to customers through the use of one-time bill credits will provide prompt relief to customers and provides for an administratively efficient and timely method to return these funds to customers. Therefore the Commission finds it reasonable to return the current DOE settlement payment net of legal costs of $12,945,141 with interest at 0.25 percent to customers through the use of one-time bill credits within 90 days of the effective date of this Final Decision.

The estimated interest accruing on the settlement funds that will also be returned to customers is $21,034. The Commission finds NSPW's proposed method of allocating the credit amounts to each customer class using the 2010 demand allocator from the class COSS in NSPW's 2010 rate case and allocating those class amounts to individual customers based on 12 months of actual kWh usage, from July 1, 2010, through June 30, 2011, to be reasonable.

Because the credits allocated to customers will be based on 12 months of actual kWh usage, from July 1, 2010, through June 30, 2011, there may be customers during this time period that subsequently left the NSPW system. Therefore, it is reasonable to require that if NSPW underrefunds the credits to the ratepayers, any such amount will be deferred until a future NSPW proceeding with interest at 0.25 percent.

To minimize customer confusion regarding the receipt of this one-time bill credit and rate increase authorized herein, it is reasonable for NSPW to notify each customer with an explanation of the DOE settlement credit. It is also reasonable for NSPW to file with the Commission a report of actual amounts refunded to customers as soon as possible after the conclusion of the refunded amounts.

Rate Proceeding for Test Year 2013

Based on preliminary financial data for 2013, NSPW is anticipating an electric revenue deficiency in the range of $20 to $30 million (3 percent to 5 percent, respectively) over and above the increase requested for 2012. A reopener case similar to what was approved by the Commission in the last NSPW rate proceeding may not be sufficient because there may be increasing costs that were not included in past reopeners, such as non-fuel O&M costs related to production and transmission functions, and the loss of wholesale customer load may significantly change cost allocation factors driving more costs to retail customers. NSPW anticipates the need to file a reopener with a broader scope or a full 2013 test-year rate case in 2012. Based on the fact that there is considerable uncertainty regarding a number of costs the company will incur in 2013, the Commission concludes that it is reasonable for NSPW to work with Commission staff to determine whether a reopener or a full case is appropriate for a 2013 test year. The Commission strongly encourages NSPW and Commission staff to consider foregoing a return on equity analysis in its next proceeding regardless of the form such proceeding may take (reopener versus full rate case).

Income Statement

NSPW, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of NSPW's 2012 electric and natural gas utility operations. Significant issues pertaining to the income statement are addressed separately below.

Electric Fuel Costs

A reasonable test-year level of monitored fuel costs is $1,163,675,937, which reflects the cost of fuel as defined by Wis. Admin. Code § PSC 116.02. The test-year monitored fuel costs divided by the test-year estimate of native energy requirements of 46,187,070 MWh results in an average net monitored fuel cost per MWh of $25.19. Appendix D shows the monthly fuel costs to be used for monitoring purposes. These amounts reflect total NSP-System native energy requirements, fuel costs, and costs per MWh. Including these costs is appropriate in view of NSPW's Interchange Agreement with NSPM, an agreement approved by the Federal Energy Regulatory Commission (FERC) that allocates shared costs between the two sister utilities. The total fuel costs are based on various indices for natural gas, oil, and forward electric prices as of November 15, 2010.

It is reasonable to monitor NSPW's fuel costs, excluding any direct CSAPR compliance costs, using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code

§ PSC 116.06(3). The level of uncertainty of non-CSAPR compliance fuel costs is not expected to be significantly changed due to the enactment of CSAPR, and non-CSAPR compliance fuel costs are not expected to be significantly more volatile in the test year than they have been in the recent past. The application of a 2 percent bandwidth is appropriate for these fuel costs. The fuel cost data in Appendix D, which does not include any costs for compliance with CSAPR, shall be used for monitoring NSPW's 2012 non-CSAPR fuel costs. The revenue requirements treatment of CSAPR compliance costs is discussed below.

Basis Differences

An important part of the test-year electric fuel cost budget relates to the forecasted market prices for electricity; that is, the prices at which the NSP System will purchase for its energy requirements and sell from its generation sources. The market prices are represented by the LMP at each of the MISO nodes. NSPW based its estimate of the LMP at the NSP load zone on the future prices at the Cinergy Hub from the Intercontinental Exchange (ICE) plus a basis difference. The NSPW basis difference relies on four years of historical data.

CUB witness Richard Hahn testified that due to the sluggish economy and an increase in natural gas production, a two-year average basis difference would provide a better estimate of MISO market prices for 2012. Mr. Hahn stated that he believes the use of the four-year historical average overstates LMPs by 13 percent. The change to the two-year historical average reduces NSP-System costs by $2,441,000, resulting in a $360,000 decrease in NSPW's 2012 revenue requirement.

The Commission determines that the use of the two-year historical average is a better match to NSP-System load. The NSPW retail revenue requirement should be reduced by

$360,000. While four-year history better reflects the impacts of seasonal variations, the two-year average better reflects the reduced load on the transmission system since the economic downturn late in 2008 and the impacts on basis differences associated with ongoing transmission improvements over the MISO footprint.

Equivalent Forced Outage Rates

CUB witness Mr. Hahn testified that the EFOR used in the company's total system fuel costs were excessive when compared to the North American Electric Reliability Council (NERC) Generating Availability Data System (GADS) average EFOR. Excessive EFOR on base-load generating units (coal and nuclear) result in additional fuel costs since the cheaper generation is diminished in the model and is replaced either by more expensive generation or purchased power.

NSPW witness Dave Horneck responded that Mr. Hahn had made an inappropriate comparison. Mr. Horneck stated that if Mr. Hahn were to calculate averages for the other generating units in the country based on the same method used by the company, the company's rates are not higher on average and the company's plants do not have any reliability challenges. Mr. Horneck stated that the primary difference between the company's EFOR and the NERC-GADS EFOR is the GADS events that are included in the calculation. The NERC-GADS EFOR calculation excluded many GADS event types that impact plant production that must be included to have a reasonable production cost model. NERC-GADS EFOR exclude event type "MO" or maintenance outages. These are typically maintenance events that are scheduled on a Monday to occur on the Sunday of the next week and that outage does not factor into the plant's EFOR; however, it will clearly impact the plant's generation for that year. When forecasting generation and production costs more than a year in advance, it is not appropriate to guess at what maintenance outages may occur during the year. Therefore, one approach is to include this type of event in the calculation of the EFOR. NSPW includes all GADS events in its calculation with the exception of certain Reserve Shutdown, Planned Outage, and Non-Curtailing events.

This process has been used in the company's rate filings at least as far back as 2001. Mr. Horneck stated that the monitored fuel costs year-to-date for 2011 through September is within 0.16 percent of authorized costs for the year. He further pointed to his comparison of actual versus authorized generation for coal and nuclear units separately for 2008-2010 which showed that actual generation for coal and nuclear units were less than the authorized levels for each of 2008-2010. If the Commission were to require the company to use the EFORs proposed by Mr. Hahn, the company would likely significantly under-recover its fuel costs.

NSPW provided a comparison of the company's EFOR and the NERC-GADS average EFOR. Exhibit 1.22 showed that the five-year average NERC defined EFOR for company owned plants is lower than the industry average for comparable base load generating units. The Commission determines the EFOR that includes event "MO" not included in the NERC-GADS EFOR as proposed by NSPW for use in PROSYM is reasonable for the 2012 test year. In future rate proceedings, NSPW should show and explain the difference between NERC-GADs EFOR and the EFORs that reflect the inclusion of "MO" events.

Nobles Wind Farm Capacity Factor

The Nobles Wind Farm achieved commercial operation in late 2010 and the 201 megawatt (MW) wind farm was forecasted in the NSPW filed fuel plan to operate at its designed rated capacity factor of 41 percent. The company bases the forecast of wind generation on the average production of prior years, using as much historical data as possible. Since no historical data was available for the Nobles Wind Farm, the 2012 original estimate was based on the design capacity factor. Mr. Horneck adjusted the January 2011 capacity factor to the design capacity factor because the January actual is likely low due to being the first month of commercial operation. Mr. Horneck adjusted May and June 2011 capacity factors to the design capacity factor because there were internal transformer failures that caused turbines to be taken out of service. These changes result in an estimated capacity factor for 2012 of 37 percent.

Mr. Horneck proposed 2012 fuel costs be increased by $2.021 million for the NSP System level ($0.300 million Wisconsin retail) and the associated production tax credit reduced by $1.515 million for the NSP System level ($0.375 million Wisconsin retail). The total increase requested in the Wisconsin retail revenue requirement is therefore $0.675 million.

Commission staff witness Mr. Wagner raised concerns with NSPW requesting to collect new items late in a rate proceeding. While the Commission continues to be hesitant to accept a utility's adjustments late in a proceeding, use of NSPW's amended capacity factor is reasonable in this case given that actual operating data, which was not available until late in this proceeding, is more accurate than the design rated capacity factor that was submitted with the original filing.

It is reasonable to estimate the 2012 generation from the Nobles Wind Farm should be based on the adjusted actual capacity for 2011 of 37 percent.

CSAPR Compliance Costs

NSPW witness Donald Reck requested that the Commission lower the fuel tolerance band to plus or minus 1.0 percent in his prefiled direct testimony. Commission staff witness Mr. Wagner testified that the Commission should not move from the plus or minus 2.0 percent bandwidth without a determination that the utility is facing extreme and unusual circumstances.

NSPW witness Mr. Horneck presented testimony indicating the potential fuel cost for CSAPR compliance of $12.891 million on an NSP System level ($1.912 million Wisconsin retail) for 2012. NSPW is not requesting upfront recovery of CSAPR compliance costs, but requested the Commission to considered the risk of incurring compliance cost when selecting the appropriate tolerance bandwidth under the fuel rules.

The Commission determines NSPW has risk of incurring significant CSAPR compliance costs.

The U.S. Environmental Protection Agency (EPA) issued a final version of CSAPR on July 6, 2011, and published it as a final rule in the *Federal Register* on August 8, 2011. This rule replaces EPA's 2005 Clean Air Interstate Rule, and is designed to address the transport of air pollution across state boundaries for 27 eastern states. CSAPR establishes new, more stringent levels of allotted sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emission allowances for the states, including Wisconsin and its utilities.

Utilities may meet the new emission standards in several ways, which include retiring older generating plants, changing the dispatch of plants, purchasing power from other utilities, installing pollution-control equipment, and purchasing allowances through a limited trading program. Pending legal challenges to CSAPR also make estimates of its 2012 cost impacts uncertain. It is possible that CSAPR implementation could be delayed to exclude part or all of the test year, or that the rule could be modified.

In light of this uncertainty, Commission staff offered the Commission several options to consider with respect to the revenue requirements treatment of CSAPR compliance costs and also noted that the Commission could use a hybrid of these methods or a totally different approach, if it wished. The alternatives offered were: (1) no deferral of incremental CSAPR-related fuel costs or tightening of the fuel rules bandwidth; (2) no deferral of incremental CSAPR-related fuel costs, but tighten the fuel rules bandwidth to 0.5 percent; (3) elimination of the fuel rules bandwidth for 2012, setting the bandwidth to plus or minus zero percent; and (4) deferral of incremental CSAPR-related fuel costs, without tightening of the fuel rules bandwidth, but excluding estimated CSAPR-related fuel costs from the revenue requirement.

Given the high degree of uncertainty associated with the 2012 cost of CSAPR compliance, and the need to avoid raising customer costs unnecessarily, the Commission chooses to not include any CSAPR-related costs in NSPW's 2012 revenue requirement. The Commission finds instead that it is reasonable to defer any direct 2012 CSAPR compliance costs. The Commission further finds that these direct CSAPR costs should be considered with a zero percent bandwidth as permitted by Wis. Admin. Code § PSC 116.06(3). A zero percent bandwidth will ensure that neither the ratepayers nor the shareholders are at risk for over- or under-payment for prudently incurred costs.

Direct CSAPR compliance costs may include, but may not be limited to: (1) the actual cost of allowances purchased and used; (2) the incremental cost of purchased power agreements entered into solely for CSAPR compliance purposes; (3) the costs associated with the re-dispatch of plants for CSAPR compliance purposes; (4) plus or minus the increased or decreased costs for coal that is lower or higher in SO_2, as compared to what is included in monitored fuel costs; and (5) minus any revenues received from the sale of emission allowances. The Commission delegates authority to the Administrator of the Gas and Energy Division to determine whether some or all of the above, or other costs, shall be included in the definition of direct CSAPR costs. The utility is also authorized to accrue carrying costs on any deferred CSAPR balances, at the utility's authorized short-term debt rate until the collection of any deferred amounts is concluded.

Commission staff shall work with NSPW, CUB, and other interested intervenors who participated in this proceeding to work out the details of the deferral mechanism. If disagreements arise between NSPW, CUB, Commission staff, and other participating interested intervenors as to the details of the deferral mechanism, authority is delegated to the Administrator of the Gas and Energy Division to resolve any such disagreements.

NSPW shall meet with Commission staff on a regular basis to keep staff apprised of the strategies being used to comply with CSAPR, any changes to those CSAPR compliance strategies, and the related compliance costs incurred or to be incurred. NSPW shall also provide supporting documentation for any deferred CSAPR compliance costs reported in its monthly fuel cost reports, so that Commission staff can report quarterly to the Commission on CSAPR costs and strategies.

CUB requested that NSPW be required to participate in a statewide collaborative designed to examine least-cost options for CSAPR compliance. Because of the very limited time to organize such a collaborative before CSAPR takes effect, and the potential uniqueness of each utility's compliance strategy, the Commission will not require NSPW to participate in such a collaborative.

Annual Fuel Plan and Monthly Fuel Monitoring Reports

CUB requested that the Commission include order points requiring NSPW to file a single fuel cost plan for the 2013 test year that complies with Wis. Admin. Code § PSC 116.03 of the new fuel rules, and includes the same level of operation and cost detail for each utility-owned resource that is currently included in NSP's monthly fuel reports. CUB also requested that additional detail on purchases and sales be added to both the annual fuel plan and monthly fuel report filings. Additionally, CUB requested that the Commission establish a detailed and specific definition of monitored and non-monitored fuel costs.

NSPW replied that the company provides adequate information to allow the Commission and intervenors to conduct a thorough review and analysis of the annual fuel cost plans in advance of a rate case test-year. Further, the monthly fuel reports provide all the information necessary to effectively monitor fuel costs on an after-the-fact basis.

In view of the foregoing, the Commission elects not to require the filing of a single fuel plan, but directs Commission staff to work with all applicable Wisconsin utilities to address the issues brought forward by CUB concerning the annual fuel cost plan and monthly electric fuel report filings.

MGP Site Clean-up Costs

In the mid-1990's, NSPW was named a potentially responsible party (PRP) for a contaminated site near a former MGP in Ashland, including both city and company-owned property and sediments in Chequamegon Bay (Ashland Site). EPA placed the Ashland Site on the National Priorities List in 2002. EPA has recently selected a remedy to clean up the Ashland Site with estimated costs that range from $83 million to $97 million with a margin of error of plus 50 percent to minus 30 percent of the actual project costs. EPA also identified three other PRPs beside NSPW. Cleanup of the Ashland Site is expected to begin in 2012.

Current Commission policy, which has been in place for many years, uses a process that defers MGP site remediation costs as they are actually incurred. The deferral of MGP site cleanup costs allows the Commission to (1) determine if these costs meet its guidelines before they are recovered in rates, and (2) shift a portion of the cost burden to the utility's shareholders with a multiple-year amortization of the deferral and no rate recovery of the carrying costs on the unamortized deferred balances. The recovery policy is designed to share responsibility for the MGP site cleanup between customers and shareholders by requiring customers to pay for the cost of the cleanup over a four- to six-year time period. This regulatory treatment has applied to all Wisconsin utilities that have had MGP site cleanup costs since 1993, when the Commission first established its policy in Wisconsin Power and Light's rate case docket 6680-UR-108.[1]

In this proceeding, NSPW requested the Commission grant an exception to its MGP site cleanup cost policy by including $3,427,000 in test-year natural gas revenue requirement for future expected MGP cleanup costs at the Ashland Site. NSPW's proposal to start collecting for future MGP cleanup costs is an interim proposal and does not address the full impact of anticipated costs and potential future recoveries from third parties. NSPW is looking at a number of alternatives, and is in ongoing discussions with Commission staff on the feasibility and desirability of various alternatives. The potential magnitude of the future liability for, and circumstances of, the cleanup at the Ashland Site may warrant a different ratemaking approach than what NSPW proposed in the interim in this proceeding.

The Commission is interested in a ratemaking approach that can address the full costs of the cleanup. Such approach will require more development and analysis. In addition, the current status of the cleanup, including insurance proceeds, does not present a pressing need to include recovery of costs in this proceeding. The Commission therefore finds it reasonable to continue

[1] In making this decision, the Commission considered that even though the MGP facilities had been removed from service for over 40 years, and as such, MGP cleanup costs were not related to the provision of utility service to its current customers, current regulations required responsible parties to investigate and cleanup the contaminated MGP sites. On the other hand, the Commission recognized that any increase in the value of the MGP site, arising after its cleanup, would accrue entirely to the benefit of the utility's shareholders if the land was later sold.

its established MGP sharing guidelines in this rate case proceeding, whereby ratepayers are responsible for paying for the MGP costs net of insurance recoveries after they are incurred and are reviewed, and shareholders are responsible for paying the carrying costs on unamortized deferred balances. Because of the significant future costs projected for the Ashland Site, the Commission may consider alternatives to its established MGP site cleanup cost accounting and cost recovery guidelines for this particular MGP site in a future proceeding. However, the Commission finds it reasonable that any deviation from its current guidelines for this project will require a balanced approach of sharing costs between the NSPW ratepayers and shareholders. It is also reasonable for NSPW to work with Commission staff in developing alternate ratemaking methods for the MGP cleanup costs at the Ashland Site to be presented to the Commission in a future NSPW rate proceeding.

Annual Merit Pay Factors

NSPW's filed payroll forecast for the test year included wage increases in 2011 of 2.5 percent for all employees, and wage increases in 2012 of 3.0 percent for non-union employees and 2.5 percent for union employees. Commission staff's forecasted payroll reflected wage increases for 2011 and 2012 for non-bargaining employees of 1.5 percent each year and wage increases in 2011 and 2012 of 2.5 percent each year for union employees under contract. NSPW subsequently proposed to reduce its 2012 merit base salary increase from 3.0 percent to 2.5 percent.

NSPW maintained that the company balances factors such as reviewing external market surveys regarding base salary increases, comparing potential increases in base salary to bargaining employees, economic conditions, and company performance, to arrive at an equitable increase in base salaries. For bargaining unit employees, the annual increases are typically associated with amounts negotiated in labor contracts. Commission staff's forecasted merit increases for non-union employees reflect current economic conditions and impacts on businesses and small-use customers from recent increases in their utility bills, while still providing utility employees some wage adjustment.

In order to reflect the current economic conditions in Wisconsin, the Commission concludes it is appropriate to incorporate 1.5 percent payroll merit increases in 2011 and 2012 for non-union employees and 2.5 percent payroll merit increases in 2011 and 2012 for union employees under contract in the development of test year payroll expense and related taxes.

Annual Incentive Plan Compensation

The non-bargaining employee cash compensation includes two components: base salary and the Annual Incentive Plan (AIP). Eligible employees have a targeted annual incentive expressed as a percentage of base salary. Target levels assume 100 percent achievement of individual, business area, and corporate objectives. In order for any AIP payments to occur, Xcel Energy must meet certain financial and operational goals. Commission staff reduced NSPW's 2012 payroll O&M expense by $2,407,000 to eliminate the costs associated with the AIP. Commission staff also reduced pension and benefits expenses and payroll tax expenses associated with the AIP expenses by $330,000.

NSPW maintained that the Commission should allow recovery of all AIP costs because it allows the total cash compensation to be competitive with the relevant market, it is a cost savings approach to providing cash compensation, and it is consistent with the standards and best practices of public and private companies in the U.S.

Consistent with the other the large investor-owned utilities in Wisconsin in which the costs associated with incentive pay plans are not included in revenue requirements, and the current economic conditions in Wisconsin, it is appropriate for the Commission to limit the financial impacts on ratepayers and exclude these costs from NSPW's revenue requirements.

Uncollectible Accounts Expense

Commission staff's estimate of test-year uncollectible accounts expense was derived by multiplying its forecasted sales revenue to residential, commercial and industrial customers at present rates, by an historical percentage of net write-offs to applicable sales revenue.

NSPW opposed the Commission staff's method of forecasting Uncollectible Accounts Expense for two reasons. First, the Commission staff method applies the ratio of net write-offs to revenues at present rates instead of revenues at proposed rates. Second, it relies solely on actual net uncollectible write-offs instead of actual FERC Account 904, Uncollectible Account Expense, to calculate the ratio. Regarding the application of the ratio of net uncollectible write-offs to total revenues at present rates, Commission staff recognized that there is a relationship between revenues and uncollectible accounts expense. However, there are procedural problems with using proposed rates to estimate uncollectible accounts expense. If the forecast of uncollectible accounts expense is based on proposed revenues, the adjustment process would become iterative. In response, NSPW proposed to make the uncollectible accounts expense the last adjustment in the revenue requirement calculations to proposed rates and exclude uncollectible accounts expense from the calculation of final revenue requirement in determining the adjustment. This type of adjustment has not been made in prior NSPW cases or in rate proceedings for other major Wisconsin investor-owned utilities for a number of reasons.

First, the net write-off percentage derived by Commission staff does not normally apply to all sales of electricity and/or natural gas; hence, one would need to know the rate design in order to derive the appropriate level of revenue deficiency that the net write-off percentage should be applied to. Second, the amount of the increase in uncollectible accounts expense relating to the revenue deficiency is usually not material.

NSPW also objected to estimating uncollectible expense utilizing only net uncollectible write-offs because it does not produce an accurate estimate of uncollectible expenses including the reserve estimate. Commission staff uses the historical actual net write-offs as a basis for its test-year forecast, which eliminates the uncertainty of the estimated write-offs booked through the reserve account. As long as Commission staff consistently uses the net write-off method to forecast uncollectible expense, it should not matter that the company has booked reserves because the historical actual net write-offs should be the best indicator in trending future expenses without the uncertainty of how the reserve is estimated on a monthly or annual basis. Commission staff has used this net write-off method of forecasting NSPW uncollectible expenses in past proceedings as well as in the other utilities' rate proceedings. The Commission therefore reaffirms its position in this proceeding and finds that Commission staff's method of forecasting uncollectible accounts expense is reasonable.

Nuclear Operating and Maintenance Expenses

WIEG recommended that the Commission defer the increase in the company's nuclear O&M expense in the test year over the historical norm and amortize the deferred amounts over the remaining lives of the nuclear generating units because they include non-recurring increased O&M expenses. WIEG argued that the increased O&M expenses relate to the extended power uprate (EPU) activities at the Monticello nuclear power plant and to the Monticello and Prairie Island nuclear power plant life extension (lifecycle management) activities.

NSPW disputed WIEG's assumptions. Rather, the reason nuclear O&M expense is increasing is due to increasing labor and security costs, regulatory fees, nuclear outage amortization costs, and rent expense. The costs associated with the EPU and lifecycle management work are typically capitalized, consistent with WIEG's argument.

The Commission agrees with NSPW that the nuclear O&M increases are not due to the extended power uprate at the Monticello nuclear power plant and lifecycle management activities at the Monticello and Prairie Island nuclear power plants, and there is no basis to assume that nuclear O&M costs will resume to the 2005-2007 levels. It is therefore not appropriate to adjust the nuclear O&M expenses in the test year.

Nuclear Depreciation

WIEG recommended that the Commission reduce the depreciation expense incurred by the company through the Interchange Agreement to reflect the full 20-year life extensions recently approved by the Nuclear Regulatory Commission (NRC) for the Prairie Island nuclear units. WIEG also recommended that the Commission amortize the nuclear depreciation reserve surplus reflected in the amounts charged to the company through the Interchange Agreement over five years and that the difference be captured in an escrow account as a regulatory asset to offset the nuclear depreciation reserve surplus.

NSPW agreed that the depreciation expense should be reduced to reflect the 20-year life extension recently approved for the Prairie Island nuclear units, which was already reflected in Commission staff's forecasted revenue requirement. NSPW did not agree with WIEG's proposal to amortize the nuclear reserve surplus. NSPW argued the current depreciation calculation required by the Minnesota Public Utility Commission (MPUC) uses the remaining life method to account for any imbalance that may exist in the depreciation reserve with every annual evaluation. The method is self-correcting and will spread any reserve surplus equitably to all customers over the remaining life.

The Commission agrees with NSPW. The remaining life method of depreciation authorized by the MPUC and used by this Commission is self-correcting and will spread any reserve surplus equitably to customers over the remaining life of the utility plant. It is therefore appropriate to reduce depreciation expense to reflect the full 20-year life extensions recently approved by NRC for the Prairie Island nuclear units and not appropriate to amortize the nuclear depreciation reserve surplus over five years.

Kansas Property Tax

NSPW requested to recover property taxes associated with natural gas storage in the state of Kansas through its purchased gas adjustment clause (PGAC). In 2004, the Kansas Legislature passed a statute that re-defined "public utility" to include any entity with natural gas stored underground in Kansas even though it may have no utility operations in Kansas. NSPW is among the companies being billed property tax for stored natural gas, and joined in a lawsuit with just over 40 other companies that were subjected to this tax. The joint lawsuit is currently under review in the Kansas Court of Appeals, but the tax continues to be in effect. While other companies have recovered the tax in their PGAC, in Wisconsin the tax was put into base rates at the direction of the Commission in the NSPW 2006 rate case, docket 4220-UR-114.

The Kansas property tax is an *ad valorem* tax,[2] based on the assessed value of gas stored in the state of Kansas. As such, it is appropriately recorded in account 408.1, and should also be forecasted as such. Consistent with the Commission's decision to include the Kansas property tax in Account 408 in docket 4220-UR-114 and in the Wisconsin Power and Light rate case in docket 6680-UR-114, the Kansas property tax is appropriately recorded and forecasted in account 408.1, Taxes Other than Income Taxes.

Energy Efficiency and Conservation Activities

Customer Service Conservation

NSPW's proposed 2012 natural gas and electric customer conservation activities consist of several energy efficiency services for residential and business customers. These include its farm rewiring program, which assists farmers to upgrade their electrical wiring and install energy efficiency measures, its Partners in Energy Savings program, which provides energy education kits to low-income households, and Energy Center of Wisconsin (ECW) membership dues, among other activities. ECW dues go towards research, education and training, and general administration. These activities are essentially the same as those approved by the Commission in docket 4220-UR-116. While the proposed 2012 customer service conservation activities are generally appropriate, it was brought to the attention of Commission staff that overlap exists between ECW's education and training activities funded by NSPW and education and training activities funded by Focus on Energy. As both of NSPW customer conservation funds and Focus on Energy funds come from ratepayers, this was of concern to Commission staff. To reduce this

[2] The Uniform System of Accounts for Private Natural Gas Utilities prescribed by the Public Service Commission, includes special instructions for Accounts 408.1 and 408.2, and reads in part: "A. These accounts shall include the amounts of ad valorem, gross revenue or gross receipts, taxes, state unemployment insurance, franchise taxes, federal excise taxes, social security taxes, and all other taxes assessed by federal state, county, municipal, or other local governmental authorities, except income taxes."

overlap and duplication, it is reasonable for NSPW to work with Commission staff and Focus on Energy Program Administrator in order to ensure that ratepayer funds dedicated to education and training are sufficiently coordinated.

Measures of Success

As a requirement of docket 05-BU-100, NSPW sets measures of success each year to show that funds dedicated to customer service conservation are spent effectively. However, under this docket the Commission did not define customer service conservation activities and did not provide direction for alignment of these activities with the statewide energy efficiency programs. As a result, current NSPW measures of success are largely activity-based rather than results-based. It is reasonable for NSPW staff to work with Commission staff to develop measures of success for its customer service conservation program. These measures of success should be structured to redefine, and better align, NSPW's customer service conservation activities with the statewide programs. NSPW must receive Commission staff acceptance of the changes before they are implemented.

Conservation Budget and Escrow Adjustment

NSPW proposed a 2012 conservation escrow budget of $12,010,399, with $9,263,041 allocated to electric operations and $2,747,358 allocated to natural gas operations. Commission staff's analysis of conservation expenses included reviewing the proposed test-year conservation expenditures, forecasting the over-spent balance in the conservation escrow at the beginning of the test year, and reviewing NSPW's forecasted amortization expense associated with previously escrowed conservation expenditures. As a result of this analysis, Commission staff forecasted a $2,252,078 over-spent balance at January 1, 2012, for electric operations, and a $535,147 over-spent balance at January 1, 2012, for natural gas operations. The Commission staff forecasted revenue requirement includes the amortization of the estimated over-spent balances over the two-year biennial period 2012 and 2013, or $1,126,039 test year amortization of the estimated electric over-spent balance and a $267,574 test year amortization of the estimated natural gas over-spent balance.

The reasonable level of expensed conservation costs recoverable in rates for the 2012 test year is $10,389,080 for electric operations and $3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of $9,263,041 plus an escrow adjustment of $1,126,039 to reflect the estimated overspent balance as of January 1, 2012, of $2,252,078, amortized over two years. The level for natural gas operations consists of the conservation budget of $2,747,358 plus an escrow adjustment of $267,574 to reflect the estimated overspent balance as of January 1, 2012, of $535,147 amortized over two years.

Summary of Income Statement

In addition to the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to NSPW's filed operating income statements are appropriate. Accordingly, the estimated Wisconsin retail electric and natural gas utility operating income statements at present rates for the 2012 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Retail Electric (000's)	Retail Natural Gas (000's)
Operating Revenues		
Sales	$569,018	$123,226
Other Operating Revenues	1,779	486
Total Operating Revenues	$570,797	$123,712
Operating Expenses		
Production Expense	$347,542	$ ---
Purchased Gas Expense	---	83,922
Gas Storage Expense	---	420
Transmission Expenses	(5,355)	---
Distribution Expenses	21,759	7,799
Customer Accounts Expenses	9,714	3,214
Customer Service & Sales Expenses	12,653	3,554
Administrative & General Expenses	34,024	5,907
Total Operation & Maintenance Expenses	$420,337	$104,816
Depreciation Expense	56,425	9,364
Amortization Expense	(182)	51
Taxes Other Than Income Taxes	21,196	1,911
State Income Taxes	3,241	(239)
Federal Income Taxes	(4,131)	(819)
Deferred Income Taxes – Net	20,596	3,238
Investment Tax Credits Restored	(531)	(26)
Total Operating Expenses	$516,951	$118,296
Chippewa Flambeau Improvement Company Income	39	---
Net Operating Income	$ 53,885	$ 5,416

Average Net Investment Rate Base

Allowance for Funds Used During Construction

NSPW requested to accrue excess AFUDC on all CWIP, which is consistent with the accrual methodology used by the other Wisconsin utilities. The company currently only accrues excess AFUDC on non-production and non-transmission CWIP based on prior request and Commission authorization. This treatment does not allow NSPW the opportunity to earn the returns authorized by this Commission because the use of the FERC AFUDC rate results in the under-recovery of the company's full carrying costs from Wisconsin's retail customers.

The Commission has a policy to include short-term debt in the weighted average cost of capital (WACC) and typically excludes CWIP from rate base. Under this policy, the use of the FERC-prescribed rate to accrue AFUDC results in the under-recovery of a utility's carrying costs. More specifically, the use of the FERC AFUDC rate results in the short-term debt costs being double counted. Retail customers receive the benefit of the lower cost of short-term debt twice – once in the return on rate base calculation and again in the FERC AFUDC calculation.

Consistent with the calculation of AFUDC for other Wisconsin utilities, it is appropriate to permit NSPW to accrue AFUDC on all CWIP at the WACC instead of at the FERC AFUDC rate. This rate treatment eliminates the double counting of short-term debt, thereby allowing NSPW to recover the full carrying costs from retail customers, and is appropriate as long as the accrual of excess AFUDC above the FERC calculated AFUDC does not flow though the interchange agreement, either from or to NSPW.

Summary of Average Net Investment Rate Bases

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to NSPW's filed average net investment rate bases are appropriate. Accordingly, the estimated Wisconsin retail electric and gas utility average net investment rate bases for the 2012 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Retail Electric (000's)	Retail Natural Gas (000's)
Utility Plant in Service	$1,735,643	$220,275
Less: Accumulated Reserve for Depreciation	831,598	124,757
Net Utility Plant	$904,045	$95,518
Add: Fuel Inventory	11,385	---
Natural Gas in Storage	---	6,955
LNG/Propane Fuel Inventory	---	354
Materials and Supplies	4,133	578
Investments in Associated Companies	537	---
Less: Accumulated Deferred Income Taxes	186,816	17,791
Customer Advances – net of tax	15,370	1,490
Average Net Investment Rate Base	$717,914	$84,126

Pro Forma Rate of Return

The adjusted net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2012, results in a rate of return on average net investment rate base of 7.51 percent for Wisconsin retail electric utility operations and 6.44 percent for Wisconsin retail natural gas utility operations.

Ratio of Net Investment Rate Base Plus CWIP to Capital Applicable to Utility Operations Plus Accumulated Deferred Investment Tax Credit Information

In 2004, Commission staff sent all of the large investor-owned utilities a copy of its initial data request which includes 80 questions about the various areas of Commission staff's audit. It is requested that utilities provide the responses to these questions at the time they submit their rate applications.

One of the areas in which Commission staff has requested information is the Ratio of Net Investment Rate Base plus CWIP to Capital Applicable to Utility Operations Plus Accumulated Deferred Investment Tax Credit (ratio). The ratio is a mechanism used to adjust the weighted cost of capital so that, when it is applied to net investment rate base, it provides a return not only on net investment rate base, but also on net working capital. In past rate cases, including this one, NSPW has provided the numerator of the ratio, which is net investment rate base plus CWIP, and the denominator of the ratio, which is capital applicable to utility operations plus accumulated deferred investment tax credit, but it has not provided the working capital account balances for which the ratio provides a return in the format requested by Commission staff. Thus, the Commission is unable to determine whether the company's request with respect to this item is reasonable. The Commission needs to see the forecasted working capital balances by month and compare them to historical amounts for these items in order to determine whether the company's forecasted ratio is reasonable.

Since the ratio provides a return on working capital, it is reasonable to expect the company to provide a complete forecast of its balance sheet, including working capital accounts, in its rate filings. Therefore, in future rate filings, it is reasonable and the Commission directs NSPW to file a forecasted ratio by month for the bridge period and the test year that includes all of the components of the balance sheet, including working capital account balances, in ratio format, in order to receive a return on working capital.

Financial Capital Structure and Dividend Restriction

The long-term range for NSPW's common equity ratio, on a financial basis, found reasonable in docket 4220-UR-116 was 50 to 55 percent common equity. In this proceeding, the Commission finds that this range remains reasonable. The exact level of the common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing NSPW at a given time. Furthermore, the Commission will continue to evaluate the appropriate capitalization in subsequent proceedings.

With the rebalancing of NSPW's capitalization, it is necessary to forecast test-year equity infusions from and special dividends to Xcel Energy to maintain a test-year average equity near a target level within the approved range. An appropriate target level for the test-year average common equity measured on a financial basis is 52.50 percent. This target level is consistent with the 50 to 55 percent range established by the Commission. This target level shall be further examined in NSPW's next rate proceeding.

The treatment of off-balance sheet obligations associated with NSPW's operating leases was an uncontested issue. Adjustments for these off-balance sheet obligations are made by Standard and Poor's (S&P) and other financial analysts when calculating various financial ratios, including the total debt to total capital ratio. Consequently, it is reasonable that any debt equivalent associated with NSPW's off-balance sheet obligations, including operating leases, be included in determining NSPW's financial capital structure. A 100 percent factor adjustment for calculating the debt equivalents of the operating leases is used in this docket. Consequently, a reasonable estimate of the amount of off-balance sheet debt equivalents to be imputed into NSPW's financial capital structure is $7,638,707.

To independently examine off-balance sheet debt obligations, it is reasonable to require that NSPW submit detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum: (1) the minimum annual lease and purchased power adjustment (PPA) obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies documentation is not available.

Subsidiary debt was also included in the financial capital structure. A reasonable estimate of subsidiary debt is $1,945,000. No imputation is made for guarantees.

Incorporating the above off-balance sheet debt equivalents and other Commission determinations, NSPW's financial capital structure for the test year will consist of 52.50 percent equity, 41.10 percent long-term debt, 5.41 percent short-term debt, 0.20 percent subsidiary debt, and 0.78 percent debt equivalence for off-balance sheet obligations. The 52.50 percent, on a financial basis, falls within the common equity guideline of 50 to 55 percent.

Assessing the reasonableness of NSPW's capital structure depends upon three important principles. First, capital structure decisions must be based on NSPW's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility to NSPW and to the Commission to allow proper utility investment now and in the future. Third, the dividend policy of NSPW should be similar to typical electric utility dividend practices as long as NSPW is below the estimated test year common equity ratio.

The utility's needs must take precedence over non-utility needs if ratepayers are to be protected. The Commission is responsible for protecting ratepayers from utilities that grant a higher priority to non-utility needs. The identification of utility needs goes beyond foreseeable needs. NSPW must have flexibility to finance both foreseen and unforeseen capital requirements.

The Commission recognizes the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices.

Consequently, NSPW may not pay standard dividends, including pass-through of subsidiary dividends, if its calendar-year average common equity ratio, on a financial basis, is or will fall below the test-year authorized target level of 52.50 percent.

Regulatory Capital Structure and Cost of Capital

Commission staff deducted from the utility's equity the non-utility investments or other equity adjustments on which ratepayers should not pay an equity return for ratemaking purposes. Consequently, a reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consist of 52.59 percent equity, 41.89 percent long-term debt, and 5.52 percent short-term debt.

Short-Term Debt

NSPW's test-year capital structure contains approximately $52,693,714 of short-term debt. The interest rate associated with the short-term indebtedness is the commercial paper rate. A reasonable estimate of the average cost of short-term commercial paper for NSPW for the test year is 0.40 percent. This forecast is based on the average of test-year commercial paper rate estimates provided by the *Blue Chip Financial Indicators*. This is a reasonable and objective method of determining NSPW's short-term debt costs. Excluded from this cost are the administrative costs associated with the commercial paper program, which will be treated as an administrative expense rather than as an administrative adder to the interest rate.

Long-Term Debt

NSPW's test-year long-term debt included $100,000,000 of indebtedness proposed to be issued during the test year. A reasonable interest rate for the proposed bonds is 4.69 percent. The resulting embedded cost of long-term debt is 6.15 percent for the test year.

Return on Common Equity

The principle factor used to determine the appropriate return on equity is the investors' required return. Authorized returns less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investor's required return would provide windfalls to utility investors as they would receive returns that are in excess of the necessary level. Such high returns would be unfair to utility ratepayers who ultimately are responsible for paying for those returns. If the investors' required return could be measured precisely, setting the authorized return would be straightforward. Because the return cannot be measured precisely, determining the appropriate return on equity is typically one of the most contested issues in a rate proceeding. In this proceeding, NSPW proposed a rate of return of 10.75 percent. Commission staff suggested that the appropriate return on equity be set somewhere in the range from 10.00 to 10.50 percent and used 10.30 percent in its revenue requirement calculation.

In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers. Among the considerations this Commission takes into account is that, while the financial models show that the required returns are declining, NSPW has entered into a major construction phase. Balance is struck most reasonably in this proceeding by authorizing a return on equity capital of 10.40 percent. A 10.40 percent return should allow NSPW to attract capital at reasonable terms without unduly burdening consumers with excessive financing costs.

Capitalization Ratios

Accordingly, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$502,201	52.59%	10.40%	5.47%
Long-Term Debt	399,987	41.89	6.15	2.58
Short-Term Debt	52,694	5.52	0.40	0.02
Total Utility Capital	$954,882	100.00%		8.07%

The weighted cost of capital of 8.07 percent is reasonable for NSPW for the test year. It generates an economic cost of capital of 11.74 percent and a pre-tax interest coverage ratio of 4.60 times on the regulatory capital structure and 4.50 percent on the financial capital structure.

Rate of Return on Rate Base

The 8.07 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of NSPW's average net investment rate base plus CWIP for the test year is 94.72 percent of capital applicable primarily to utility operations plus deferred investment tax credit. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base. Accordingly, the rate of return on average Wisconsin retail electric and natural gas utility net investment rate bases, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

	Retail Electric	Retail Natural Gas
Cost of Capital	8.07%	8.07%
Average Percent of Utility Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	94.72%	94.72%
Percent Return Requirement Applicable to Net Investment Rate Base	8.52%	8.52%

Revenue Requirement

On the basis of the findings in this Final Decision, a $12,155,000 increase in Wisconsin retail electric utility revenues and a $2,924,000 increase in Wisconsin retail natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates in this proceeding and are computed as follows:

	Retail Electric	Retail Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	7.51%	6.44
Required Return on Average net Investment Rate Base	8.52%	8.52
Earnings Deficiency as a Percent of Average Net Investment Rate Base	1.01%	2.08%
Average Net Investment Rate Base (000's)	$717,914	$84,126
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	$7,281	$1,752
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$12,155	$2,924

Electric Cost-of-Service

Both NSPW and Commission staff submitted the results of several COSS. The two major electric COSS issues contested in this proceeding are the allocation of production capacity costs and the allocation of distribution system costs. The allocation of these costs significantly affects the cost responsibility for providing electric service.

NSPW supported the range of the allocations from two of its COSS; one that allocated production capacity costs using a 100 percent (12 CP) demand allocation and another that used a blended allocation of 57.3 percent (12 CP) demand and 42.7 percent energy. The Commission staff preferred the results of its TOU study, which used a blended allocation of 60 percent (12 CP) demand and 40 percent energy. Both NSPW and Commission staff COSS include allocations of distribution system costs that are a blend of demand and weighted customers.

WIEG advocated for using a cost study that allocates production capacity costs based on either NSPW's 4 CP or 12 CP electric cost study that reflected a 100 percent demand allocation. The results of these cost studies showed that the large commercial and industrial customers should get a lower than average increase. CUB endorsed the use of a cost study that uses a blended allocation of 38.6 percent (12 CP) demand and 61.6 percent energy to allocate production capacity costs. This is the same production allocator that NSPW supported in its last base rate case. CUB also argued for a different allocation of the electric distribution system costs. CUB favored allocating the customer service portion of the distribution system costs based on customers and all the rest of these costs based on demand. The results of CUB's preferred cost study allocations showed that the residential and small general service customers should get a lower than average increase.

There was a wide range of results in the COSS submitted in this proceeding as well as significantly differing opinion on which of these studies should be used for determining revenue responsibility. The Commission routinely considers electric COSS as a guide along with other factors in its decisions regarding the allocation of revenue responsibility. In this proceeding, the

Commission maintains that relying on the results of more than one COSS, as well as other factors is reasonable for the determination of an appropriate allocation of the revenue responsibility.

Electric Revenue Allocation

Allocating the increase in NSPW's revenue requirement for the provision of electric service was also a significant contested issue in this proceeding. Both NSPW and Commission staff submitted a comprehensive allocation of the proposed electric revenue increase. Despite the fact that the electric revenue increase supported by NSPW and Commission staff differed significantly, both proposed revenue allocations that were very similar. The main differences between NSPW and Commission staff was in the degree to which the increases for the large customers' service at transmission voltages were lower than the overall increase and the increases for the large primary and secondary voltage customers were higher than the overall increases. Commission staff's revenue allocations reflected slight mitigations in the increases for the small customers and within the large customer classes, based on bill impact considerations.

WIEG proposed that the Cg-9 and Cp-1 rates classes receive less than the overall percentage increase and that the RTP rate class should receive no increase. CUB proposed that the residential customer classes receive no more than one-half of the overall increase, based on the range of cost studies that used a blended demand and energy allocation of production related costs and an allocation of most of the distribution plant costs based on demand, except for the costs for street lighting, and services.

The Commission routinely considers factors other than COSS such as bill impacts, existing relationships between rate classes, and the overall magnitude of the revenue change, in its decisions regarding the allocation of revenue responsibility. The results of the COSS introduced in this case support a variety of revenue allocations. The Commission determines that the class revenue changes and rate design proposed by Commission staff, in Exhibit 6.8, adjusted for the final revenue requirement are reasonable, except for two rate design provisions discussed below.

Electric Rate Design

NSPW's rate design reflected increases in customer charges, energy charges, and demand charges and for all of the customer classes, which included higher than average increases for demand charges and lower than average increases for energy charges. NSPW's rate design also included two provisions that primarily affected the large high voltage and high load factor customers. These include a significant increase for the high voltage discounts and a significant increase in the high load factor energy charge credits. NSPW proposed these two changes to move these customer's rates closer to the cost-of-service. In rebuttal testimony, NSPW provided information regarding an alternative based on high voltage discounts and the high load factor energy charge credits that were between NSPW's initial proposal and Commission staff's proposal on these two items, which the Commission considers to be an appropriate compromise position.

Commission staff's rate design included increases in energy and demand charges, but no change in the customer charges. This rate design reflects higher than average increases for the demand charges and lower than average increases for the energy charges, similar to NSPW's design. It also includes an increase in the voltage discounts for the transmission service that is less than NSPW proposed and no change in the high load factor energy charge credit.

WIEG argued that the rate design for the Cg-9, Cp-1 and the RTP classes should include greater than average increases for the demand charges and less than average increases for the energy charges. WIEG also supported the changes in the high voltage discounts and high load factor energy charge credits that NSPW proposed.

The Commission finds the Commission staff electric rate design, including the 2005 Wisconsin Act 141 rate factors, adjusted for the final revenue requirement and the following decisions on specific rate changes, to be reasonable. Increasing NSPW's voltage discounts from 5.5 to 6.5 percent for customers served at the transmission transformed voltage and from 6.0 to 7.0 percent for customers served at the transmission untransformed voltage is reasonable. The Commission also determines that it is reasonable to increase the high load factor energy charge credit to $0.00800 per kWh. The authorized electric rates contained are shown in Appendix B.

Commissioner Callisto dissents with regard to the Commission's determination to increase the high load factor energy charge credit. He would have supported a smaller increase in this credit in light of the substantial steps taken in this rate case to increase the voltage discounts, which benefit substantially the same customers as those receiving the high load factor energy credit.

Electric Tariff Changes

NSPW proposed various miscellaneous changes to its electric rule and regulation tariffs, which affect tariff schedules Ex-19, Ex-19.1, Ex-34, Ex-35, Ex-38 and Ex-49. These changes were unopposed. The Commission finds it reasonable to approve these proposed changes to NSPW's electric rule and regulation tariffs.

NSPW also proposed language changes to its lighting tariffs, in that same exhibit, which affect schedules S-1, Ms-2.1, Ms-3.1, Ms-4.1, Ms-4.2, and Ms-6. Part of these changes included inserting the words "regular daytime work" between "72" and "hours" that appear in the current lighting tariffs. Commission staff proposed an alternative to NSPW's proposed wording that would replace "72 hours" with "three business days." NSPW did not contest Commission staff's suggested changes. The Commission finds the changes to the lighting tariffs initially proposed by NSPW and modified by Commission staff's alternative language to be reasonable.

Customer-Owned Generation Tariffs

NSPW requested authorization to cancel its existing PG-2 tariff and to unbundle its parallel generation service into a three-tier tariff structure, and to base buyback rates on MISO LMPs. NSPW argued that LMP based buyback rates would more accurately represent its true avoided energy cost, and that such a transition would reduce the potential for over- and under-payment for energy purchased from parallel generation customers.

LMP is an appropriate proxy for utility avoided energy cost. NSPW's proposed LMP pricing of parallel generation tariffs is reasonable as this pricing is driven by the model of lowest substitutable cost and stands to benefit both the company and the ratepayer. Historically, parallel generation buyback rates have also reflected the cost of capacity as represented by the cost of a gas-fired combustion turbine. In transitioning to market based parallel generation rates, it is reasonable that the company's parallel generation tariffs continue to recognize the value of capacity in buyback rates by indicating that, should MISO implement a capacity market, NSPW shall implement a capacity credit reflecting the MISO capacity market pricing method. Customers under the parallel generation tariffs with renewable generation facilities that generate renewable credits may negotiate a renewable credit rate for any renewable energy sold to NSPW. Customers shall retain the right to refuse a renewable premium offered by NSPW and retain any renewable credits.

NSPW proposed changes to its Pg-1 net energy billing tariff, increasing the current 20 kW limit to 100 kW and modifying the energy credit rate such that Pg-1 customers would be credited for monthly net energy sales to the company at an avoided cost rate based on the proposed Pg-2A tariff rate. Pg-1 customers would retain all renewable credits and other attributes associated with any net energy sales made to the company. To mitigate rate impact to existing customers, those customers who have initiated service under the current Pg-1 tariff prior to January 1, 2012, and who have generation with name plate capacity of 20 kW shall continue to be served subject to the terms of the existing Pg-1 tariff until the Commission issues its order in the company's next general rate case.

NSPW also proposed requiring net energy billing customers to size their generation facilities to match their load requirements and indicated its intention to cancel its Pg-1.1 net energy billing service tariff for non-renewable generators. Commission staff proposed modifying NSPW's proposal to allow customers to net their generation and consumption annually. Pg-1 customers would be allowed to carry forward kWhs of surplus generation from month to month. Annually, NSPW would perform a true-up calculation with any credit issued to the customer reflecting this annual netting approach. Any remaining annual net surplus kWh would be credited to the customer at the avoided cost rate proposed by NSPW. Additionally, under Commission staff's proposal, Pg-1 customers would not be required to match their generation facilities to their annual load requirements.

NSPW subsequently revised its proposal to allow for the carry forward of kWhs of surplus generation from month to month with an annual true-up performed prior to the beginning of the company's summer months. However, NSPW opposed Commission staff's proposal to allow for annual netting arguing that customers should not be allowed to carry-forward large amounts of accumulated excess generation for later use. Under NSPW's revised proposal, an annual true-up calculation would only consider any remaining carry forward kWh balance and would not allow for annual netting. NSPW also removed the load matching requirement under its revised proposal, but argued that if the Commission determines it reasonable to allow the customer to net their generation and consumption annually, that the company views the load matching requirement feature as essential.

The Commission determines that it is reasonable to increase the capacity limit of NSPW's Pg-1 net energy billing tariff to 100 kW. In addition, it is reasonable to allow customers to net their generation and consumption annually as this better meets customer expectations and encourages the installation of small distributed renewable generation. Net energy billing customers shall be allowed to carry forward kWhs of surplus generation from month to month. Annually, the company shall perform a true-up calculation with any credit issued to the customer reflecting an annual netting period. It is reasonable that annual net surplus customer-generated kWhs be credited to the customer at the avoided-cost rate in order to limit the customer's ability to extract unreasonably large benefits through a mismatch between generation capacity and consumption as this is inconsistent with the intent of net billing. In light of changes to this tariff, the Commission determines it is not reasonable to require net energy billing customers to size their generation facilities to match their annual load requirements. In order to reduce the impact to customers who might otherwise have stranded generation assets, it is reasonable to allow existing net energy billing customers who have generation with name plate capacity of 20 kW or less to continue to be served subject to the terms of the existing Pg-1 tariff until the Commission issues its order in the NSPW's next general rate case. It is reasonable to cancel the company's Pg-1.1 net energy billing tariff for non-renewable generation facilities.

NSPW requested authorization to modify its existing Advanced Renewable Tariff (ART). The modified ART would expand eligible technologies from three to four with the addition of solar, and introduces a tiered structure that the company believes better matches production costs with generator size and reduces the levels of uncertainty and potential confusion around what technologies qualify for the tariff and the tariff's ultimate total subscription cap. In addition to any applicable technology and tier specific project size limits and enrollment caps, the modified ART will be considered fully subscribed when small renewable distributed generation accounts for 0.25 percent of the company's retail electric sales for 2009. Customers subscribing to the original ART, issued on January 8, 2008, will remain subject to the terms and conditions of the original ART. However their annual generation will count towards the appropriate technology generation cap, if one exists, and towards the entire program cap of the modified ART. The Commission determines that NSPW's proposed ART modifications are reasonable.

NSPW proposed changes to its Pg-2.1 Parallel Generation-Hydroelectric Energy Purchase Service tariff rates, which is presently closed to new customers. NSPW proposed updating the rate levels for the single customer currently being served under the tariff, keeping the capacity payment at the customer's contracted level of $0.0422/kWh, and lowering the energy purchase rate to $0.0300/kWh. The Commission determines that NSPW's proposed changes to its Pg-2.1 tariff rates are reasonable.

Other Rate Design Issues

NSPW proposed the cancellation of its Customer Buyback Program Service tariff (CBP) due to a lack of customer participation over the eleven years of the tariff's existence. During that time, the CBP Buy Back Period has been declared only once in NSPW's Wisconsin service territory, and no customer opted to participate in the tariff. It is reasonable for NSPW to cancel its CBP tariff.

Commission staff suggested that NSPW begin to transition its Cg-5 general service customers from flat energy rates to TOU rates. TOU rates provide better price signals to utility customers and encourage use of the electrical system in a more efficient manner, with the long-term goal of lower utility costs and lower utility rates for all customers. TOU rates also improve customer equity by charging more for end use during on-peak periods. NSPW did not oppose Commission staff's proposal. However the company cautioned that it may incur additional overtime costs to implement a total conversion due to the workload involved and the current priorities of NSPW's Meter Department and that there may be transition problems or unanticipated costs that may arise. The Commission determines it is reasonable to direct NSPW to develop a plan to transition its Cg-5 customers to a mandatory TOU rate structure. The company shall file its plan with the Commission by March 31, 2012, to be implemented on or before January 1, 2014.

Windsource Green Pricing Program

NSPW offers a voluntary green pricing program (VRE-1) that is marketed under the name Windsource. NSPW proposed increasing the Windsource rate from $1.37 to $1.50 per

100 kWh block arguing that the program's incremental costs have risen due to decreases in NSPW's system cost of energy.

In administering its Windsource program, NSWP retires Renewable Energy Credits (RECs) in the amount equal to Windsource sales, reducing the amount of available RECs that could be put on the market. Windsource sales do not, however, directly lead to an amount of renewable energy on the NSPW System greater than the amount NSPW would otherwise have been obligated to take under the NSP System interchange agreement. Commission staff requested in the Briefing Memorandum that the Commission consider whether the retirements of RECs alone sufficiently satisfies NSPW's obligations in administering the Windsource program, or whether NSPW should take further action to ensure that sales through Windsource result in additional renewable energy on the NSPW system that the utility would not have otherwise acquired. In its Comments on the Briefing Memorandum, NSPW strongly objected to the analysis of the Windsource program and the related alternatives set forth therein.

The Commission finds it reasonable to maintain the Windsource premium at the current rate of $1.37 per 100 kWh block and to require a full analysis to be done in NSPW's next rate case on the issue of the company's Windsource voluntary green pricing program.

Natural Gas Rates and Rules

Natural Gas Cost-of-Service Studies

NSPW prepared an embedded COSS and Commission staff prepared two embedded COSS, COSS A and COSS B. The NSPW and Commission staff COSS A models are described as customer-oriented studies. Commission staff's COSS B is a commodity-oriented study. The results differ because the customer-oriented studies allocate costs associated with certain plant investments, overheads, and operating expenses to the service rate classes, in part, based on the number of customers in the respective service rate classes. COSS B allocates these costs to the service rate classes, in part, based on the commodity usage of the respective service rate classes.

It is reasonable to rely on all the natural gas COSS presented in this docket as a guide to setting rates. This has been the Commission's policy in the past and it continues to be the appropriate policy.

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized for NSPW in Appendix C of this Final Decision will provide an 8.52 percent rate of return on the average gas net investment rate base. This represents an increase of 7.44 percent in margin rates and an increase of 2.36 percent in total natural gas sales revenues.

Margin rates exclude natural gas costs. Authorized rates as set forth in Appendix C are based on the cost of supplying natural gas service to the various service rate classes and other rate setting goals. Summaries of the rate impacts on a service rate class are shown in Appendix C.

As shown in Appendix C, the natural gas COSS results in a relatively wide range of changes in the charges to the various service rate classes. To provide for historical continuity in NSPW's rates, the Commission finds it reasonable to authorize service rates that move in the direction of the natural gas COSS results, with intent to make further adjustments in that direction in subsequent rate proceedings. In moving toward the cost of service in authorized rates, the Commission tempers the rate increase to the service rate classes that, according to the cost analysis, should receive the largest percentage increases. The resulting revenue difference is recovered through the rates of the remaining service rate classes. The percentage rate increase to any individual customer will not necessarily equal the overall percentage increase to the associated service rate class, but will depend on the specific usage level of the customer.

Monthly Distribution Rates for Residential Gas Service

NSPW proposed to increase the monthly residential service charge, from $10.25 to $11.00, a 7.32 percent increase. NSPW stated that the proposed monthly residential service charge is still well below NSPW's monthly COSS amount of $20.66, and a larger increase in the customer charges relative to volumetric rate increases will reduce the rate impact on large-volume residential customers during the winter season.

The Commission determines that it is not appropriate to increase the residential customer charge. NSPW's residential customer charge is currently set at the highest level authorized by the Commission to date. Additionally, increasing the fixed portion of the bill decreases the amount of savings that customers can experience due to using less gas, which reduces a residential customer's financial incentive to conserve energy and install energy efficiency measures.

Some typical gas bills for residential service were computed to compare existing rates with new rates including the cost of gas. Such comparison is set forth in Appendix C.

Merging Commercial Service Rate Classifications

NSPW offers a number of commercial service rates based on minimum contract levels and proposed to reduce the number of commercial service rate classes from seven to four. NSPW proposed to reduce the number of commercial customer classes for the following reasons: (1) because price competition has eased, (2) the number of classes is confusing to the customer, and (3) it is administratively burdensome for the company.

Commission staff proposed to combine the Large General Service rate class and the Interruptible Group 1 rate class into one rate class. Commission staff did not propose combining other classes at this time because it resulted in undesirable rate impacts; however, an effort was made to move the various interruptible rate classes closer together. The Commission finds that consolidating rates of additional commercial service rate classes could prove to be financially adverse and that it is appropriate to mitigate the rate impacts at this time. Therefore, the Commission finds that moving the rates together at this time is reasonable with the intent to further reduce commercial class rate differences or to consolidate commercial rate classes in subsequent rate proceedings.

Presently, there is only one customer that subscribes to NSPW's largest-volume service rate class, Cg-6. Natural gas sales to this customer have been trending down rather significantly since 2007 so there is the likelihood that this customer will no longer be eligible for this service in the near future. Closing the largest volume service rate class to new customers and removing the largest volume service rate class when the existing customer no longer subscribes to this service is another approach of combining the rates of two service rate classes into one service rate classes (Groups 4 and 5). Because Cg-6 rates generate revenues that are considerably less than the cost of service results, it would be more appropriate to have new customers subscribe to Cg-5 than to subscribe to a service that has been mitigated for rate increase purposes. It is reasonable to close the largest volume service rate class, Cg-6, to new customers and to remove this class when the existing customer no longer subscribes to this service.

Effective Date

The test year commences on January 1, 2012. Under Wis. Stat. § 196.40, an order of the Commission shall take effect 20 days after it has been filed and served on the parties to the proceeding, unless the Commission specifies a different effective date in the order. The Commission finds it reasonable for this Final Decision to take effect one day after the date of mailing. Pursuant to Wis. Stat. §§ 196.19 and 196.21, the changes in rates and tariff provisions that are authorized in this Final Decision shall take effect as described below.

The Commission finds it reasonable for the authorized rate increases and all tariff provisions that restrict the terms of service to take effect January 1, 2012, provided that these rates and tariff provisions are filed with the Commission and placed in all offices and pay stations of the utility by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, it is reasonable to require that they take effect on the date they are filed with the Commission and placed in all offices and pay stations.

Order

1. This Final Decision shall take effect one day after the date of mailing.

2. The authorized rate increases and tariff provisions that restrict the terms of service shall take effect January 1, 2012, provided that NSPW files these rates and tariff provisions with the Commission and places them in all of its offices and pay stations by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, they shall take effect on the date they are filed with the Commission and placed in all offices and pay stations.

3. NSPW may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as discussed in the Opinion section and as shown in Appendices B and C. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

4. NSPW shall prepare bill inserts that properly identify the rates authorized in this Final Decision. NSPW shall distribute these inserts to customers with the first billing containing the rates authorized in this Final Decision and shall file copies of these inserts with the Commission before it distributes the inserts to customers.

5. NSPW shall work with Commission staff to develop alternative ratemaking methods to address MGP site cleanup costs at the Ashland Site for consideration in a future rate case proceeding.

6. NSPW shall return the DOE settlement proceeds and accrued interest as one-time credits on customers' bills within 90 days of the effective date of this Final Decision.

7. If NSPW underrefunds to its Wisconsin retail ratepayers any amounts from the DOE settlement funds including interest, such amounts shall be deferred until a future NSPW proceeding with interest at 0.25 percent.

8. NSPW shall notify each customer with an explanation of the DOE settlement credit.

9. NSPW shall file with the Commission a report of actual DOE settlement amounts refunded to customers as soon as possible after the conclusion of the refunded amounts.

10. NSPW shall work with Commission staff to determine whether a reopener or a full case is appropriate for a 2013 test year.

11. The electric fuel costs in Appendix D shall be used for monitoring of NSPW's 2012 non-CSAPR compliance fuel costs, pursuant to Wis. Admin. Code § PSC 116.06(3).

12. All non-CSAPR compliance fuel costs for 2012 shall be monitored using a plus or minus 2 percent tolerance band.

13. Direct CSAPR compliance costs shall be deferred, with a zero percent tolerance band and with carrying costs set at the utility's authorized cost of short-term debt.

14. Commission staff, NSPW, CUB, and other interested intervenors who participated in this proceeding shall work together to develop a specific definition of direct CSAPR compliance costs. In the event that Commission staff, NSPW, CUB, or other participating intervenors disagree with respect to the definition of direct CSAPR compliance costs, authority is delegated to the Administrator of the Gas and Energy Division to resolve any such disagreements.

15. In order that Commission staff can report quarterly to the Commission on CSAPR compliance costs and strategies, NSPW shall keep Commission staff apprised of its CSAPR compliance strategy and any changes thereto, and the associated compliance costs, by meeting regularly with Commission staff to discuss its compliance strategy and by providing supporting documentation for all deferred CSAPR compliance costs reported in its monthly fuel cost reports.

16. Commission staff shall work with all applicable Wisconsin electric utilities and CUB to address the issues brought forward by CUB concerning the annual fuel cost plan and monthly electric fuel report filings.

17. In future rate filings, NSPW shall provide a forecasted Ratio of Net Investment Rate Base Plus CWIP to Capital Applicable to Utility Operations Plus Accumulated Deferred Investment Tax Credit, which would include all of the components of the balance sheet presented in ratio format, by month, in order for the company to receive a return on its forecasted net working capital.

18. NSPW shall continue to work with Commission staff and the Focus on Energy Program Administrator to ensure that education and training offerings are well-coordinated.

19. NSPW shall work with Commission staff to develop measures of success for its customer service conservation program. The measures of success should be structured to redefine, and thereby better align, NSPW's customer service conservation activities with the statewide energy efficiency programs. NSPW must receive Commission staff acceptance of the changes before they are implemented.

20. NSPW shall record annual conservation accrual amounts of $10,389,080 for electric operations and $3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of $9,263,041 and an escrow adjustment of $1,126,039 to reflect the estimated overspent balance as of January 1, 2012, of $2,252,078, amortized over two years. The level for natural gas operations consists of the conservation budget of $2,747,358 and an escrow adjustment of $267,574 to reflect the estimated overspent balance as of January 1, 2012, of $535,147 amortized over two years.

21. NSPW shall maintain 50 to 55 percent common equity on a financial basis in its capital structure.

22. The appropriate target level for NSPW's common equity shall be further explored in the company's next rate case.

23. NSPW shall submit a ten-year financial forecast in its next rate case.

24. NSPW shall submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies documentation is not available.

25. Excluding the special dividend authorized in this docket, NSPW shall not pay dividends, including pass-through of subsidiary dividends, in excess of $31,826,077, if its actual average common equity ratio, on a financial basis, is or will fall below the test year authorized level of 52.50 percent.

26. NSPW may pay a special dividend to its parent company as it rebalances its capitalization to meet the Commission's authorized target of 52.50 percent common equity on a financial basis.

27. NSPW shall file the electric tariff language changes as proposed and consistent with discussion in the Opinion section.

28. NSPW's parallel generation tariffs shall indicate that, should MISO implement a capacity market, NSPW shall implement a capacity credit reflecting the MISO capacity market pricing method.

29. NSPW shall allow customers taking service under its parallel generation tariffs to separately negotiate a renewable credit rate for any renewable energy sold to the utility.

30. NSPW shall allow net energy billing customers to net their generation and consumption annually.

31. NSPW shall allow net energy billing customers to carry forward kWhs of surplus generation from month to month and shall allow carry forward kWhs to offset the customer's consumption. Annually, the company shall perform a true-up calculation with any credit issued to the customer reflecting an annual netting period.

32. NSPW shall file a plan with the Commission to transition the company's Cg-5 customers to a mandatory TOU rate structure by March 31, 2012, to be implemented on or before January 1, 2014.

33. A full analysis shall be required in NSPW's next rate case on the issue of the company's Windsource voluntary green pricing program.

34. NSPW is authorized to merge its Large General Service rate class and the Interruptible Group 1 rate class into one rate classification.

35. It is reasonable to close the largest volume service rate class, Cg-6, to new customers and to remove this class when the existing customer no longer subscribes to this service.

36. NSPW shall file tariffs consistent with this Final Decision.

37. Jurisdiction is retained.

Dated at Madison, Wisconsin, December 22, 2011

By the Commission:

Sandra J. Paske

Sandra J. Paske
Secretary to the Commission

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See attached Notice of Rights

Docket 4220-UR-117

PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of mailing of this decision, as provided in Wis. Stat. § 227.49. The mailing date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of mailing of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of mailing of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission mailed its original decision.[3] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: December17, 2008

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[3] *See State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

PUBLIC SERVICE COMMISSION OF WISCONSIN

Appendix A

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates | 4220-UR-117

SERVICE LIST
(October 18, 2011)

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PUBLIC SERVICE COMMISSION OF WISCONSIN
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NORTHERN STATES POWER COMPANY (WISCONSIN)

SUMMARY OF ELECTRIC REVENUE FOR TEST YEAR 2012

INDIVIDUAL RATE CLASSES	PRESENT REVENUES	AUTHORIZED REVENUES	DOLLAR INCREASE	PERCENT INCREASE
Rg-1 (Residential)	$ 194,533,689	$ 198,713,443	$ 4,179,754	2.15%
Rg-2 (Residential - Optional Time-of-Day)	11,315,404	11,560,324	244,920	2.16%
Fg-1 (Farm Service)	9,809,324	10,032,664	223,340	2.28%
Cg-6 (Optional Off-Peak Service -- Res.)	81,473	83,160	1,687	2.07%
S-1 (Automatic Protective Lighting -- Res.)	441,747	450,208	8,461	1.92%
Cg-1 (Small General - Optional Time-of-Day)	461,489	471,648	10,159	2.20%
Cg-2 (Small General Non-TOD)	43,193,302	44,147,553	954,251	2.21%
S-1 (Automatic Protective Lighting -- Com.)	559,160	569,730	10,570	1.89%
Ms-6 (Underground Area Lighting - Private)	33,714	34,314	600	1.78%
Cg-5 (General Service TOD)	84,929,501	86,499,433	1,569,933	1.85%
Cg-6 (Optional Off-Peak Service -- C&I)	233,202	238,197	4,995	2.14%
Cp-2 (Peak Controlled Non-TOD)	3,022,740	3,085,791	63,051	2.09%
Cg-9 (Large General TOD)	148,780,450	152,304,240	3,523,790	2.37%
DS-1 (Military Fac. Distrib. Service)	561,849	574,446	12,597	2.24%
Cp-1 (Peak Controlled Service)	51,935,640	53,040,447	1,104,806	2.13%
RTP-1 (Real-Time Pricing)	13,450,423	13,589,961	139,538	1.04%
Ms-2 (Company Owned Street Lighting)	3,410,061	3,469,892	59,831	1.75%
Ms-3 (Cust. Owned Incand./Fluor. Lighting)	6,848	6,971	123	1.80%
Ms-4 (Customer Owned Lighting)	584,564	595,177	10,613	1.82%
Ms-6 (Underground Area Lighting - Public)	304,754	310,184	5,430	1.78%
Ms-7 (Metered - Customer Owned Lighting)	93,221	94,975	1,754	1.88%
Mp-1 (Municipal Water Pumping)	958,720	980,615	21,895	2.28%
Mz-3 (Fire Siren Service)	4,820	4,878	58	1.20%
VRE (Voluntary Renewable Energy - Windsource)	156,591	156,591	0	0.00%
Pg-2 (Parallel Generation Service)	0	0	0	0.00%
TOTAL ELECTRIC RETAIL SALES	568,862,686	581,014,841	12,152,156	2.14%
Interdepartmental Sales	155,316	158,625	3,309	2.13%
TOTAL ELECTRIC	**$ 569,018,002**	**$ 581,173,466**	**$ 12,155,465**	**2.14%**

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
RESIDENTIAL SERVICE, Rg-1			
Customer Charge (per Month)	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Water Heating Meter Chg. (per Month per Meter)		$2.00	$2.00
Load Management Credit (per Month):			
Water Heating		$2.00	$2.00
Air Conditioning (Summer Only)		$6.00	$6.00
Energy Charge (per kWh)	Summer	11.1148 ¢	11.3780 ¢
	Non-Summer	10.0537 ¢	10.2920 ¢
RESIDENTIAL TOD SERVICE, Rg-2			
Customer Charge (per Month)	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh):	On-Peak (Summer)	20.7344 ¢	21.2320 ¢
	On-Peak (Non-Summer)	19.1472 ¢	19.6070 ¢
	Off-Peak (Summer)	5.3044 ¢	5.4210 ¢
	Off-Peak (Non-Summer)	5.3044 ¢	5.4210 ¢
FARM SERVICE, Fg-1			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Load Management Credit (per Month):			
Water Heating		$2.00	$2.00
Air Conditioning (Summer Only)		$6.00	$6.00
Energy Charge (per kWh)	Summer	11.1148 ¢	11.3780 ¢
	Non-Summer	10.0537 ¢	10.2920 ¢
SMALL GENERAL SERVICE, Cg-2			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Un-metered Cust. Charge (per Month):	Single-Phase	$4.50	$4.50
	Three-Phase	$6.50	$6.50
Water Heating Meter Chg. (per Month per Meter)		$2.00	$2.00
Energy Charge (per kWh)	Summer	11.1148 ¢	11.3780 ¢
	Non-Summer	10.0537 ¢	10.2920 ¢
Act 141 $ in Base Rates		0.0980 ¢	0.1210 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0520 ¢	0.0530 ¢
SMALL GENERAL TOD SERVICE, Cg-1			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh):	On-Peak (Summer)	20.7344 ¢	21.2320 ¢
		19.1472 ¢	19.6070 ¢
	Off-Peak (Summer)	5.3044 ¢	5.4210 ¢
		5.3044 ¢	5.4210 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
GENERAL SERVICE, Cg-5			
Customer Charge (per Month)		$30.00	$30.00
Demand Charges (per kW):	Secondary (Summer)	$11.00	$11.25
	Secondary (Non-Summer)	$9.00	$9.25
	Primary (Summer)	$10.47	$10.70
	Primary (Non-Summer)	$8.51	$8.74
Energy Charge (per kWh)	Summer	5.9105 ¢	6.0050 ¢
	Non-Summer	5.3785 ¢	5.4640 ¢
Act 141 $ in Base Rates		0.0980 ¢	0.1210 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0380 ¢	0.0380 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.53	$0.55
[Discounts Reflected Above]	Non-Summer	$0.49	$0.51
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.7000 ¢	0.8000 ¢
PEAK CONTROLLED SERVICE, Cp-2			
Customer Charge (per Month)		$40.00	$40.00
Demand Charges (per kW):			
Firm Demand:	Secondary (Summer)	$11.00	$11.25
	Secondary (Non-Summer)	$9.00	$9.25
	Primary (Summer)	$10.47	$10.70
	Primary (Non-Summer)	$8.51	$8.74
Controlled Demand:	Secondary (Summer)	$6.29	$6.54
	Secondary (Non-Summer)	$6.29	$6.54
	Primary (Summer)	$5.85	$6.08
	Primary (Non-Summer)	$5.85	$6.08
Energy Charge (per kWh)	Summer	5.9105 ¢	6.0050 ¢
	Non-Summer	5.3785 ¢	5.4640 ¢
Act 141 $ in Base Rates		0.0980 ¢	0.1210 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0280 ¢	0.0280 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.53	$0.55
[Discounts Reflected Above]	Non-Summer	$0.49	$0.51
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.800 ¢	0.800 ¢
OPTIONAL OFF-PEAK SERVICE, Cg-6			
Customer Charge (per Month):	Single-Phase	$4.00	$4.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh)	Secondary (Summer)	4.8707 ¢	4.9780 ¢
	Secondary (Non-Summer)	4.8707 ¢	4.9780 ¢
	Primary (Summer)	4.7733 ¢	4.8780 ¢
	Primary (Non-Summer)	4.7733 ¢	4.8780 ¢
Non-Authorized Use Charge (per kWh)		21.4218 ¢	21.9150 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
LARGE GENERAL TOD SERVICE, Cg-9			
Customer Charge (per Month):	Mandatory	$155.00	$155.00
	Optional	$55.00	$55.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	$9.50	$9.75
	Secondary (Non-Summer)	$7.50	$7.75
	Primary (Summer)	$9.31	$9.56
	Primary (Non-Summer)	$7.35	$7.60
	Trans. Transformed (Sum.)	$8.98	$9.12
	Tr. Transform. (Non-Sum.)	$7.09	$7.25
	Transmission (Summer)	$8.93	$9.07
	Transmission (Non-Sum.)	$7.05	$7.21
Customer Demand Charges (per kW):	Secondary	$1.23	$1.30
	Primary	$0.92	$0.97
	Trans. Transformed	$0.52	$0.55
	Transmission	$0.00	$0.00
Energy Charge (per kWh):	On-Peak (Summer)	7.5129 ¢	7.6960 ¢
	On-Peak (Non-Summer)	6.7778 ¢	6.9420 ¢
	Off-Peak (Summer)	4.4284 ¢	4.5380 ¢
	Off-Peak (Non-Summer)	4.4284 ¢	4.5380 ¢
Act 141 $ in Base Rates		0.0980 ¢	0.1210 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0370 ¢	0.0370 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	5.50%	6.50%
	Transmission	6.00%	7.00%
Voltage Discounts = [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.19	$0.19
	Primary (Non-Summer)	$0.15	$0.15
	Trans. Transformed (Sum.)	$0.52	$0.63
	Tr. Transform. (Non-Sum.)	$0.41	$0.50
	Transmission (Summer)	$0.57	$0.68
	Transmission (Non-Sum.)	$0.45	$0.54
Customer (per kW):	Primary	$0.31	$0.33
	Trans. Transformed	$0.71	$0.75
	Transmission	$1.23	$1.30
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.7000 ¢	0.8000 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
PEAK CONTROLLED TOD SERVICE, Cp-1			
Customer Charge (per Month):	Demands >200 kW	$175.00	$175.00
	Demands ≤ 200 kW	$75.00	$75.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	$9.50	$9.75
	Secondary (Non-Summer)	$7.50	$7.75
	Primary (Summer)	$9.31	$9.56
	Primary (Non-Summer)	$7.35	$7.60
	Trans. Transformed (Sum.)	$8.98	$9.12
	Tr. Transform. (Non-Sum.)	$7.09	$7.25
	Transmission (Summer)	$8.93	$9.07
	Transmission (Non-Sum.)	$7.05	$7.21
Customer Demand Charges (per kW):	Secondary	$1.23	$1.30
	Primary	$0.92	$0.97
	Trans. Transformed	$0.52	$0.55
	Transmission	$0.00	$0.00
Controlled Demand Charges (per kW):	Secondary (Summer)	$4.79	$5.04
	Secondary (Non-Summer)	$4.79	$5.04
	Primary (Summer)	$4.69	$4.94
	Primary (Non-Summer)	$4.69	$4.94
	Trans. Transformed (Sum.)	$4.53	$4.72
	Tr. Transform. (Non-Sum.)	$4.53	$4.72
	Transmission (Summer)	$4.22	$4.69
	Transmission (Non-Sum.)	$4.22	$4.69
Energy Charge (per kWh):	On-Peak (Summer)	7.5129 ¢	7.6960 ¢
	On-Peak (Non-Summer)	6.7778 ¢	6.9420 ¢
	Off-Peak (Summer)	4.4284 ¢	4.5380 ¢
	Off-Peak (Non-Summer)	4.4284 ¢	4.5380 ¢
Act 141 $ in Base Rates		0.0980 ¢	0.1210 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0340 ¢	0.0340 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	5.50%	6.50%
	Transmission	6.00%	7.00%
Voltage Discounts [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.19	$0.19
	Primary (Non-Summer)	$0.15	$0.15
	Trans. Transformed (Sum.)	$0.52	$0.63
	Tr. Transform. (Non-Sum.)	$0.41	$0.50
	Transmission (Summer)	$0.57	$0.68
	Transmission (Non-Sum.)	$0.45	$0.54
Customer (per kW):	Primary	$0.31	$0.33
	Trans. Transformed	$0.71	$0.75
	Transmission	$1.23	$1.30
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.700 ¢	0.800 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
MILITARY FACILITY DISTRIBUTION SERVICE, DS-1			
Distribution Service Charge (per kW)		$4.46	$4.56
EXPERIMENTAL REAL TIME PRICING, RTP-1			
Customer Charge (per Month)		$300.00	$300.00
Contract Demand Charges (per kW):	Secondary	$9.50	$9.09
	Primary	$9.31	$8.91
	Trans. Transformed	$8.35	$8.50
	Transmission	$8.30	$8.45
Distribution Demand Charges (per kW):	Secondary	$1.23	$1.30
	Primary	$0.92	$0.97
	Trans. Transformed	$0.52	$0.55
	Transmission	$0.00	$0.00
Energy Charges (per kWh):		Authorized Hourly Energy Prices included in the table below	
Approx. Act 141 $ in Lg.Cust. Rates		0.000 ¢	0.000 ¢
Energy Voltage Discounts (per kWh):	Primary	0.093 ¢	0.100 ¢
	Trans. Transformed	0.248 ¢	0.331 ¢
	Transmission	0.271 ¢	0.356 ¢
Limited Energy Surcharge (per kWh)		10.9500 ¢	10.9500 ¢
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.6100 ¢	0.7000 ¢

Energy Chgs. $ per kWh	Day Types 1	2	3	4	5	6	7	8
12 am - 6 am	0.05144	0.04670	0.04435	0.04009	0.03784	0.03370	0.03339	0.03174
6 am - 9 am	0.08928	0.07036	0.05995	0.06078	0.05806	0.04375	0.04334	0.03678
9 am - 12 pm	0.23092	0.15988	0.10069	0.08006	0.06605	0.05652	0.04638	0.04006
12 pm - 6 pm	0.38483	0.25460	0.14805	0.09188	0.06605	0.05652	0.04638	0.04006
6 pm - 9 pm	0.27827	0.20724	0.12437	0.08172	0.06605	0.05652	0.04638	0.04006
9 pm - 12 pm	0.08692	0.07036	0.06315	0.05616	0.04647	0.04158	0.03807	0.03572

AUTOMATIC PROTECTIVE LIGHTING, S-1	PRESENT RATES	AUTHORIZED RATES
Monthly Charges (per Unit):		
175 Watt MV Lamps (Closed)	$8.35	$8.51
250 Watt MV Lamps (Closed)	$11.12	$11.33
400 Watt MV Lamps (Closed)	$14.96	$15.24
70 Watt HPS Lamps	$5.97	$6.08
100 Watt HPS Lamps	$7.26	$7.40
150 Watt HPS Lamps	$8.77	$8.93
250 Watt HPS Lamps	$11.89	$12.11
400 Watt HPS Lamps	$16.99	$17.31

NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-2		
Monthly Charges (per Lamp):		
Overhead:		
175 Watt MV Lamps (Closed)	$12.21	$12.43
250 Watt MV Lamps (Closed)	$13.91	$14.16
400 Watt MV Lamps (Closed)	$17.20	$17.51
70 Watt HPS Lamps	$10.03	$10.21
100 Watt HPS Lamps	$10.94	$11.13
150 Watt HPS Lamps	$12.18	$12.40
250 Watt HPS Lamps	$15.15	$15.42
400 Watt HPS Lamps	$19.70	$20.05
Underground:		
175 Watt MV Lamps (Closed)	$17.89	$18.21
250 Watt MV Lamps (Closed)	$19.47	$19.82
70 Watt HPS Lamps	$15.01	$15.28
100 Watt HPS Lamps	$15.93	$16.21
150 Watt HPS Lamps	$17.17	$17.48
250 Watt HPS Lamps	$20.38	$20.74
400 Watt HPS Lamps	$24.68	$25.12
Decorative Underground:		
100 Watt HPS Lamps	$34.04	$34.65
150 Watt HPS Lamps	$35.58	$36.21
250 Watt HPS Lamps	$38.67	$39.36
400 Watt HPS Lamps	$43.17	$43.94
Maintenance Option:		
100 Watt HPS Lamps	$8.14	$8.28
150 Watt HPS Lamps	$9.71	$9.88
250 Watt HPS Lamps	$12.79	$13.02
400 Watt HPS Lamps	$17.29	$17.60

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
CUSTOMER OWNED STREET LIGHTING, Ms-4		
Monthly Charges (per Lamp):		
Group I - Energy and Maintenance:		
175 Watt MV Lamps (Closed)	$6.79	$6.91
250 Watt MV Lamps (Closed)	$8.34	$8.49
400 Watt MV Lamps (Closed)	$11.84	$12.05
700 Watt MV Lamps (Closed)	$18.73	$19.06
50 Watt HPS Lamps	$4.12	$4.19
70 Watt HPS Lamps	$4.58	$4.66
100 Watt HPS Lamps	$5.46	$5.56
150 Watt HPS Lamps	$6.48	$6.60
250 Watt HPS Lamps	$9.49	$9.66
400 Watt HPS Lamps	$13.01	$13.24
Group I - Energy and Maintenance (No Paint):		
175 Watt MV Lamps (Closed)	$6.54	$6.66
250 Watt MV Lamps (Closed)	$8.09	$8.24
400 Watt MV Lamps (Closed)	$11.59	$11.80
700 Watt MV Lamps (Closed)	$18.48	$18.81
50 Watt HPS Lamps	$3.87	$3.94
70 Watt HPS Lamps	$4.33	$4.41
100 Watt HPS Lamps	$5.21	$5.31
150 Watt HPS Lamps	$6.23	$6.35
250 Watt HPS Lamps	$9.24	$9.41
400 Watt HPS Lamps	$12.76	$12.99
Group II - Energy Only:		
100 Watt MV Lamps (Closed)	$2.64	$2.69
175 Watt MV Lamps (Closed)	$4.22	$4.30
400 Watt MV Lamps (Closed)	$9.31	$9.48
700 Watt MV Lamps (Closed)	$15.90	$16.18
35 Watt HPS Lamps	$0.88	$0.90
50 Watt HPS Lamps	$1.28	$1.30
70 Watt HPS Lamps	$1.69	$1.72
100 Watt HPS Lamps	$2.54	$2.59
150 Watt HPS Lamps	$3.92	$3.99
200 Watt HPS Lamps	$4.98	$5.07
250 Watt HPS Lamps	$6.05	$6.16
400 Watt HPS Lamps	$9.53	$9.70
1000 Watt HPS Lamps	$21.60	$21.98

NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-4.2 (Closed)			
Ornamental:			
250 Watt MV Lamps		$15.56	$15.84
400 Watt MV Lamps		$18.54	$18.87
150 Watt HPS Lamps		$15.46	$15.74
250 Watt HPS Lamps		$18.32	$18.65
UNDERGROUND AREA LIGHTING, Ms-6			
Monthly Charges (per Lamp):			
175 Watt MV Lamps (Closed)		$15.73	$16.01
100 Watt HPS Lamps		$14.01	$14.26
150 Watt HPS Lamps		$15.98	$16.26
METERED CUSTOMER OWNED STREET LIGHTING, Ms-7			
Customer Charge (per Month)		$7.25	$7.25
Energy Charge (per kWh)		5.7629 ¢	5.8780 ¢
COMPANY OWNED STREET LIGHTING, Ms-3 (Closed)			
Monthly Charges (per Lamp):			
2,500 Lumen - Incand. (AN)		$7.78	$7.92
4,000 Lumen - Incand. (AN)		$9.49	$9.66
6,000 Lumen - Incand. (AN)		$11.45	$11.65
10,000 Lumen - Incand. (AN)		$15.26	$15.53
F72H0 - Fluorescent (4AN)		$15.49	$15.77
F72H0 - Fluor. (2AN+2MN)		$13.64	$13.88
MUNICIPAL WATER PUMPING, Mp-1			
Customer Charge (per Month)		$10.00	$10.00
Minimum Charge: Cust. Chg. + All hp > 5 (per hp)		$0.80	$0.80
Energy Charge (per kWh)	Summer	11.1148 ¢	11.3780 ¢
	Non-Summer	10.0537 ¢	10.2920 ¢
Primary Voltage Energy Discount (per kWh)		2.00%	2.00%
FIRE SIREN SERVICE, Mz-3			
Minimum Charge (per Month)		$2.00	$2.00
Rate per hp of Connected Capacity		37.50 ¢	38.30 ¢
WINDSOURCE, VRE (Green Pricing Tariff)			
Energy Charge Adder		1.37 ¢	1.37 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)
ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
PARALLEL GENERATION, Pg-2			
Customer Charge (per Month):			
For Generator Rating: 21-100 kW:	Delivering < 200 amps	$6.40	$6.40
	Delivering > 200 amps	$8.60	$8.60
For Generator Rating: > 100 kW		14.80	$13.80
Standard Energy Payments - based on Delivery Voltage (per kWh):			
Transmission Voltage:	On-Peak	9.460 ¢	NSPW
	Off-Peak	3.690 ¢	proposed
	Average (for Pg-1.1)	5.700 ¢	Energy
Primary Voltage:	On-Peak	9.860 ¢	payments
	Off-Peak	3.850 ¢	that are
	Average (for Pg-1.1)	5.940 ¢	based on
Secondary Voltage	On-Peak	9.700 ¢	LMP
	Off-Peak	3.780 ¢	prices
	Average (for Pg-1.1)	5.840 ¢	
HYDRO ENERGY PURCHASE, Pg-2.1 (Closed)			
Customer Charge (per Month):			
For Generator Rating: 21-100 kW:	Delivering < 200 amps	$6.40	$6.40
	Delivering > 200 amps	$8.60	$8.60
For Generator Rating: > 100 kW		14.80	$13.80
Capacity Rate (Primary) paid per kWh:			
20-Year Option:			
Service beginning in 1992		4.220 ¢	4.220 ¢
Average Energy Rate (Primary):			
For Service in 1996 & After Until Changed by PSC Order		3.430 ¢	3.430 ¢
ELECTRIC SERVICE EXTENSION ALLOWANCES			
Residential & Farm Service:			
(for Rg-1, Rg-2, Fg-1)		$426.00	$452.00
General Service -- Non-Demand:			
(for Cg-1, Cg-2, Mp-1, Mz-3)		$482.00	$490.00
General Service -- Demand:			
(for Cg-5 and Cp-2) per kW:		$72.00	$67.00
Large General Service -- Demand:			
(for Cg-9 and Cp-1)			
Secondary (per kW):		$53.00	$59.00
Primary (per kW):		$40.00	$50.00
Street and Area Lighting:			
(for Ms-2, Ms-4, Ms-6)		$94.00	$82.00

Northerm States Power Company

Present and Authorized Distribution Service Revenue by Customer Class

Distribution Classes and Other Cost Categories	Volumes	Margin Revenue at Current Rates	Margin Cost of Service COSS A	COSS B	Margin Revenue at Authorized Rates	Change from Revenue at Current Rates	Percent Margin Change
Residential							
Residential (Rg-1)	61,727,662	$ 24,211,273			$ 26,235,940	$ 2,024,667	8.36%
Subtotal	61,727,662	$ 24,211,273	$ 27,936,126	$ 21,731,833	$ 26,235,940	$ 2,024,667	8.36%
Commercial & Industrial, Cg-1 (0 to 29,999)							
Commercial - Firm (Cgl-SSS-F)	49,371,525	$ 10,539,717			$ 11,086,038	$ 546,321	5.18%
Commercial - Contract (Cgl-SSS-CD)	3,558,475	$ 594,488			$ 621,533	$ 27,044	4.55%
Commercial - Interdepart. (Cgl-SSS-F)	180,040	$ 31,657			$ 33,745	$ 2,088	6.60%
Commercial - Transport (Cg-1-CSS)	522,920	$ 69,869			$ 75,935	$ 6,066	8.68%
Subtotal Cg-1	53,632,960	$ 11,235,730	$ 9,387,904	$ 11,443,362	$ 11,817,250	$ 581,520	5.18%
Commercial & Industrial, Cg-2 (30,000 to 199,999)							
Commercial - Interruptible (Cg-2-SSS-CD)	858,650	$ 96,829			$ 96,314	$ (515)	(0.53)%
Commercial - Interruptible (Cg-2-SSS-I)	10,000,000	$ 1,406,589			$ 1,510,251	$ 103,662	7.37%
Commercial - Transport (Cg-2-CSS)	878,028	$ 80,866			$ 89,998	$ 9,131	11.29%
Subtotal Cg-2	11,736,678	$ 1,584,285	$ 1,133,883	$ 1,915,308	$ 1,696,563	$ 112,278	7.09%
Commercial & Industrial, Cg-3 (200,000 to 499,999)							
Commercial - Interruptible (Cg-3-SSS-I)	2,335,857	$ 221,106			$ 240,651	$ 19,545	8.84%
Commercial - Transport (Cg-3-CSS)	1,697,693	$ 107,899			$ 117,369	$ 9,470	8.78%
Subtotal Cg-3	4,033,550	$ 329,005	$ 393,319	$ 684,734	$ 358,020	$ 29,015	8.82%
Commercial & Industrial, Cg-4 (500,000 to 1,999,999)							
Commercial - Interruptible (Cg-4-SSS-I)	9,378,459	$ 632,479			$ 683,634	$ 51,156	8.09%
Commercial - Transport (Cg-4-CSS-I)	5,020,104	$ 198,111			$ 223,832	$ 25,721	12.98%
Subtotal Cg-4	14,398,563	$ 830,590	$ 1,146,187	$ 2,216,527	$ 907,467	$ 76,877	9.26%
Commercial & Industrial, Cg-5 (2,000,000 to 5,999,999)							
Commercial - Interruptible (Cg-5-SSS-I)	3,551,025	$ 213,661			$ 222,428	$ 8,767	4.10%
Commercial - Inter-InterD (Cg-5-CSS-I)	1,119,000	$ 87,309			$ 95,558	$ 8,250	9.45%
Commercial - Transport (Cg-5-CSS-I)	16,927,934	$ 631,674			$ 699,206	$ 67,532	10.69%
Subtotal Cg-5	21,597,959	$ 932,644	$ 1,202,618	$ 2,788,865	$ 1,017,192	$ 84,549	9.07%
Commercial & Industrial, Cg-6 (6,000,000+)							
Commercial - Transport (Cg-6-CSS-I)	5,674,262	$ 165,920			$ 181,808	$ 15,888	9.58%
Subtotal Cg-6	5,674,262	$ 165,920	$ 372,593	$ 792,001	$ 181,808	$ 15,888	9.58%
Act 141 Billing Adjustments			$ 642,699	$ 642,699		$ -	-
Total Gas Rate Margin Revenue	172,801,634	$ 39,289,446	$ 42,215,330	$ 42,215,330	$ 42,214,240	$ 2,924,794	7.44%
Authorized Rate Revenue Change		$ 42,213,562			$ 42,213,562	$ (2,924,116)	(7.44)%
Revenue Excess (Shortfall) at Proposed Rates		$ (2,924,116)			$ 678	$ 678	0.00%
Cost of Gas		$ 83,679,423			$ 83,679,423	$ -	-
Total Gas Rate Revenue		$ 122,968,870			$ 125,893,663	$ 2,924,794	2.38%
Plus Other Revenue		$ 731,459			$ 731,459	$ -	-
Total Gas Revenue		$ 123,700,329			$ 126,625,122	$ 2,924,794	2.36%

Northerm States Power Company

Present and Authorized Gas Rates

		Present Rates		Authorized Rates
Residential				
Monthly Customer Charge - (Rg-1)	$	10.25	$	10.25
Volumetric Charges:				
Distribution Service Charge - (Rg-1)	$	0.1769	$	0.2077
Peak Day Backup Charge (SSS-F)	$	-	$	0.0020
Gas Acquisition Charge (SSS-F)	$	0.0336	$	0.0336
Commercial (Cg-1, Annual Usage < 30,000 therms)				
Monthly Customer Charge	$	20.00	$	20.00
Additional Meter Charge	$	4.00	$	4.00
Volumetric Charges:				
Distribution Service Charge	$	0.1304	$	0.1420
Peak Day Backup Charge (SSS-F)	$	-	$	-
Gas Acquisition Charge (SSS-F, SSS-CD)	$	0.0321	$	0.0321
Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)				
Monthly Customer Charge	$	100.00	$	100.00
Transportation Administrative Charge	$	50.00	$	50.00
Volumetric Charges:				
Distribution Service Charge - (Cg-2-SSS-CD)	$	0.0950	$	0.0984
Distribution Service Charge - (Cg-2-SSS-I)	$	0.0880	$	0.0984
Peak Day Backup Charge (SSS-F)	$	-	$	0.0047
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$	0.0256	$	0.0256

Northerm States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)		
Monthly Customer Charge	$ 200.00	$ 300.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0610	$ 0.0653
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)		
Monthly Customer Charge	$ 350.00	$ 350.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0459	$ 0.0549
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therms)		
Monthly Customer Charge	$ 500.00	$ 550.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0417	$ 0.0480
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256

Northerm States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Commercial (Cg-6, Annual Usage 6,000,000+ therms)		
Monthly Customer Charge	$ 625.00	$ 625.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0375	$ 0.0443
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Base Average Cost of Gas Rates:		
Commodity ("Comm") rate	$ 0.5904	$ 0.4987
Peak Day Demand ("D1") rate	$ 0.0975	$ 0.1183
Annual Demand ("D2") rate	$ 0.0100	$ 0.0095
Balancing ("Bal") rate	$ 0.0039	$ -
Act 141 Volumetric Distribution Rates 1/		
Residential	$ 0.0054	$ 0.0113
Commercial (Cg-1, Annual Usage < 30,000 therms)	$ 0.0112	$ 0.0152
Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)	$ 0.0112	$ 0.0152
Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)	$ 0.0112	$ 0.0152
Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)	$ 0.0112	$ 0.0152
Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therm	$ 0.0112	$ 0.0152
Commercial (Cg-6, Annual Usage 6,000,000+ therms)	$ 0.0112	$ 0.0152

1/ Act 141 volumetric distribution rates are included in the above volumetric Distribution Service Charges.

Northerm States Power Company

Monthly Residential Bill Comparison

Gas Costs	Summer	Winter
Firm Sales Service	0.5082	0.6265

Monthly Use Therms	Current Customer Charge	Current Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Customer Charges	Authorized Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
Rg-1: Residential Firm Sales Service During Summer Months												
5	$ 10.25	$ 1.05	$ 11.30	$ 2.54	$ 13.84	$ 10.25	$ 1.22	$ 11.47	$ 2.54	$ 14.01	$ 0.16	1.18%
10	$ 10.25	$ 2.11	$ 12.36	$ 5.08	$ 17.44	$ 10.25	$ 2.43	$ 12.68	$ 5.08	$ 17.77	$ 0.33	1.88%
18 avg.	$ 10.25	$ 3.79	$ 14.04	$ 9.15	$ 23.19	$ 10.25	$ 4.38	$ 14.63	$ 9.15	$ 23.78	$ 0.59	2.55%
25	$ 10.25	$ 5.26	$ 15.51	$ 12.71	$ 28.22	$ 10.25	$ 6.08	$ 16.33	$ 12.71	$ 29.04	$ 0.82	2.91%
50	$ 10.25	$ 10.53	$ 20.78	$ 25.41	$ 46.19	$ 10.25	$ 12.17	$ 22.42	$ 25.41	$ 47.83	$ 1.64	3.55%
75	$ 10.25	$ 15.79	$ 26.04	$ 38.12	$ 64.15	$ 10.25	$ 18.25	$ 28.50	$ 38.12	$ 66.61	$ 2.46	3.83%
95	$ 10.25	$ 20.00	$ 30.25	$ 48.28	$ 78.53	$ 10.25	$ 23.11	$ 33.36	$ 48.28	$ 81.64	$ 3.12	3.97%
125	$ 10.25	$ 26.31	$ 36.56	$ 63.53	$ 100.09	$ 10.25	$ 30.41	$ 40.66	$ 63.53	$ 104.19	$ 4.10	4.10%
150	$ 10.25	$ 31.58	$ 41.83	$ 76.23	$ 118.06	$ 10.25	$ 36.50	$ 46.75	$ 76.23	$ 122.98	$ 4.92	4.17%
200	$ 10.25	$ 42.10	$ 52.35	$ 101.64	$ 153.99	$ 10.25	$ 48.66	$ 58.91	$ 101.64	$ 160.55	$ 6.56	4.26%
300	$ 10.25	$ 63.15	$ 73.40	$ 152.46	$ 225.86	$ 10.25	$ 72.99	$ 83.24	$ 152.46	$ 235.70	$ 9.84	4.36%
Rg-1: Residential Firm Sales Service During Winter Months												
5	$ 10.25	$ 1.05	$ 11.30	$ 3.13	$ 14.44	$ 10.25	$ 1.22	$ 11.47	$ 3.13	$ 14.60	$ 0.16	1.14%
10	$ 10.25	$ 2.11	$ 12.36	$ 6.27	$ 18.62	$ 10.25	$ 2.43	$ 12.68	$ 6.27	$ 18.95	$ 0.33	1.76%
18	$ 10.25	$ 3.79	$ 14.04	$ 11.28	$ 25.32	$ 10.25	$ 4.38	$ 14.63	$ 11.28	$ 25.91	$ 0.59	2.33%
25	$ 10.25	$ 5.26	$ 15.51	$ 15.66	$ 31.18	$ 10.25	$ 6.08	$ 16.33	$ 15.66	$ 32.00	$ 0.82	2.63%
50	$ 10.25	$ 10.53	$ 20.78	$ 31.33	$ 52.10	$ 10.25	$ 12.17	$ 22.42	$ 31.33	$ 53.74	$ 1.64	3.15%
75	$ 10.25	$ 15.79	$ 26.04	$ 46.99	$ 73.03	$ 10.25	$ 18.25	$ 28.50	$ 46.99	$ 75.49	$ 2.46	3.37%
95	$ 10.25	$ 20.00	$ 30.25	$ 59.52	$ 89.77	$ 10.25	$ 23.11	$ 33.36	$ 59.52	$ 92.88	$ 3.12	3.47%
125 avg.	$ 10.25	$ 26.31	$ 36.56	$ 78.31	$ 114.88	$ 10.25	$ 30.41	$ 40.66	$ 78.31	$ 118.98	$ 4.10	3.57%
150	$ 10.25	$ 31.58	$ 41.83	$ 93.98	$ 135.80	$ 10.25	$ 36.50	$ 46.75	$ 93.98	$ 140.72	$ 4.92	3.62%
200	$ 10.25	$ 42.10	$ 52.35	$ 125.30	$ 177.65	$ 10.25	$ 48.66	$ 58.91	$ 125.30	$ 184.21	$ 6.56	3.69%
300	$ 10.25	$ 63.15	$ 73.40	$ 187.95	$ 261.35	$ 10.25	$ 72.99	$ 83.24	$ 187.95	$ 271.19	$ 9.84	3.77%
Avg. Annual Residential Billing												
678	$ 123.00	$ 142.72	$ 265.72	$ 411.99	$ 677.71	$ 123.00	$ 164.96	$ 287.96	$ 411.99	$ 699.95	$ 22.24	3.28%

Northern States Power Company-Wisconsin
Docket 4220-UR-117

Monitored Fuel Costs for 2012

	Total Fuel Rules Cost	System Requirements (MWh)	Monthly $/MWh	Cumulative $/MWh
Jan	$99,045,452	4,058,358	$ 24.41	$ 24.41
Feb	$90,986,728	3,654,100	$ 24.90	$ 24.64
Mar	$101,419,601	3,778,325	$ 26.84	$ 25.36
Apr	$84,847,423	3,404,680	$ 24.92	$ 25.26
May	$86,606,716	3,579,490	$ 24.20	$ 25.06
Jun	$98,797,327	4,015,882	$ 24.60	$ 24.97
Jul	$112,344,453	4,457,466	$ 25.20	$ 25.01
Aug	$111,639,356	4,331,355	$ 25.77	$ 25.12
Sep	$93,503,996	3,688,746	$ 25.35	$ 25.14
Oct	$87,711,327	3,611,448	$ 24.29	$ 25.06
Nov	$96,082,739	3,595,974	$ 26.72	$ 25.20
Dec	$100,690,819	4,011,247	$ 25.10	$ 25.19
	$1,163,675,937	46,187,070	$ 25.19	